CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

INTEGRATED ENERGY POLICY REPORT COMMITTEE

INTEGRATED ENERGY POLICY REPORT

COMBINED HEAT AND POWER/DISTRIBUTED

GENERATION MARKET AND POLICY

WORKSHOP

CALIFORNIA ENERGY COMMISSION

1516 NINTH STREET

HEARING ROOM A

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THURSDAY, APRIL 28, 2005

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REPORTED BY:

PETER PETTY

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APPEARANCES

COMMITTEE MEMBERS PRESENT

John Geesman, Commissioner and Presiding Member

James Boyd, Commissioner and Associate Member

Melissa Jones, Adviser to Commissioner Geesman

Michael Smith, Adviser to Commissioner Boyd

STAFF PRESENT

Scott Tomashefsky

Mark Rawson, PIER Energy Systems Integration

ALSO PRESENT

Nick Lenssen, Primen

Richard Brent, Solar Turbines

David Dyck, Valero Energy Corporation

Ed Yates, CLFP

Ralph Renne, EXAR

Michael Alcantar, CAC/EPUC

Paul-Frederik Bach, Eltra

Ken Darrow, EEA

Snuller Price, E3

Maureen Lennon, CA Cogeneration Council

Joseph Velasquez, Sempra

Daniel Tunnicliff, SCE

Susan Buller, PG&E

Jack Brouwer, UC Irvine

APPEARANCES (continued)

PUBLIC COMMENT

R. Thomas Beach, CA Cogeneration Council

Barry Lovell, Berry Petroleum

Peter Evans, New Car Technologies

Todd O'Connor, O'Connor Consulting Services, Inc.

Ellen Petrill, EPRI

Jose Luis Contreras, Navigant

Jane Turnbull, League of Women Voters

Kevin Duggan, Capstone Turbine Corporation

Gerome Torribio, SCE

Kevin Best, RealEnergy

George Willsee, Ingersoll-Rand

Steve Toth, BP

I N D E X

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P R O C E E D I N G S

COMMISSIONER GEESMAN: This is a workshop for the Energy Commission's 2005 Integrated Energy Policy Report. I'm John Geesman, the Commissioner who presides over the Integrated Energy Policy Report Committee.

To my right is Commissioner Jim Boyd, who is the Associate Member of the Committee, and was the Presiding Member of the 2003 IEPR Committee. To my left is Melissa Jones, my Staff Advisor.

This is a subject that Commissioner Boyd and I have dealt with for, probably 27 or 28 years now, in one form or another. We were both quite actively involved in the state's promotion of what we called at the time cogeneration, in the late 1970's.

And I think that the results, in a slightly different set of circumstances, from those efforts proved to be quite beneficial to the state. We were on a course, at that time were challenged for new generations.

The utility supply plan did not appear to state government to be either technologically feasible or financially feasible, and our prospects of going into the 1980's looked quite stark.

The resulting standard offer solicitation federal development purpose statute resulted I think initially in excess of 6,000 megawatts available. Very quickly, substantially larger volume thereafter.

In retrospect, they know there were a lot of criticisms made about the price assumptions in those contracts, and obviously they provoked a strong reaction from both the utilities and from some of the larger utility customers in the 1990's.

Today we face a different set of circumstances, but I think we're also at a reflection point in terms of trying to structure the electricity supply system that will best suit California's needs over the course of the next 10-15 years.

We appear largely by default to have reverted into a utility procurement process to meet our new generation supplies. We've had a great deal of difficulty establishing the appropriate contract format or appropriate financial structure that will result in necessary new generation coming online.

We've not proven particularly adept at replacing aging infrastructure.

To the surprise of many, environmental permitting does not seem to have been a particular constraint over the last five years, and the state has emphasized its desire to see much greater reliance on renewable technologies going forward.

It occurs to Commissioner Boyd and myself -- and I certainly thank Commissioner Boyd for the attention that he has riveted on this subject beginning in the 2003 Integrated Energy Policy Report -- it occurs to us that cogeneration should play a much larger role going forward in meeting our supply needs than it has in the recent past.

One of the perplexing features of this subject is you talk to state policymakers, whether they be at this agency or the CPUC or the Legislature, and there is overwhelming support for greater reliance on what I still habitually call cogeneration, or distributed generation.

And there have been any number of state policy initiatives designed to encourage that. And yet, we still don't seem to have elicited the volumes that had been hoped for.

Our staff has underway a collaborative effort with the Public Utilities Commission. Commissioner Boyd and I will submit our committee report to our Commission later this fall. The staff has recently put up on our website a couple of draft consultant reports that I think have some very valuable subject matter. We'll hear more about those in this workshop.

But our effort is to formulate, this year, an agenda whereby we can derive a greater reliance on these technologies going forward than we have in the recent past.

With that, Commissioner Boyd?

COMMISSIONER BOYD: Thank you. Good morning everybody. We've been joined up here by my Advisor, Mike Smith. Thank you, Commissioner Geesman, for those kind words in highlighting my un-success at putting this subject. But I'm still here pushing.

You reminded me that, during the darkest hours of the energy crisis, I was a member of the generation team from the prior governor. And my whole effort was to try to push this subject a lot more, to let these people give us the electricity, the other group had tried and failed miserably.

But I didn't have a lot of success, and a lot of financial barriers were thrown in the way of the little success that we did have.

But I appreciate the fact that Commissioner Geesman feels as strongly perhaps as I do about the need to do this, and that he has such a prominent piece of the 2005 IEPR process.

Certainly the staff has done a tremendous amount of work on this subject, as is evidenced by the piles and piles of materials that we've been provided. And as evidenced by the fact that it's going to take two days to talk about the entire subject, not just one.

So, there's a lot of potential, and as you can see we're not quitting, although my term is going to run out here in one and 2/3rd's years, so I've got to do something pretty quick. But in any event, I'm fairly confident we'll do something.

And the last thing I'll say is I've got a terrible cold, and it will prevent me from having long run-on sentences, so maybe you'll be spared some of my prose today.

With that, I better turn it over to

Scott before I lose my voice again.

MR. TOMASHEFSKY: Good morning everyone. I'm pleased that we're all able to get together and talk about the CHP issues.

A couple of housekeeping items. You'll notice the small microphones. The relevance of those, if you come up and speak, is that that is how our Court Reporter can actually make sure what you're saying is actually in the record.

So, when you do speak, try to come up to the table or the podium at the appropriate time, as opposed to just shouting out from your chair. That'll slow us down a second or two, but at least from an accuracy standpoint that will work much better.

Also, the workshop is being webcast, as well as the one tomorrow. Documents are all posted, with the exception of the UCI presentation, which is available on the table up front. That should be posted sometime this morning, so anyone who's listening online should have access to everything that we have here in the room.

Mark Rawson, who's with the PIER Energy Systems Integration section, he's been our distributed energy resource program manager, is co-hosting today and tomorrow with us. So you may see me, you may see Mark, we'll figure that out as we go along.

We also wanted to thank Rachel MacDonald of our staff also, who works with Mark closely and has been responsible for putting together binders, documents, posting, and all the other logistics that we generally don't like to deal with. She's done it in a nice manner, so thanks to Rachel.

Just as a couple of brief speaking points, and then we'll turn it over the rest of the festivities. We had indicated at the end of the 2003 IEPR process, we really made a verbal commitment to address cogeneration issues much more closely.

The issue came up actually late in the process, especially in a hearing we had in Bakersfield, where the question was asked "well, why aren't we addressing it?"

And as Commissioner Geesman had noted, it's not that we're not interested in it, but we have used that as kind of a jumpstart to do what we're doing here.

As part of that we authorized EPRI to

lead an effort to develop the market assessment that is posted on the web, and is the subject of most of the discussion you'll hear today.

The assessment itself updates a study that was done in 1999, where we actually looked at CHP potential at that time. And we had concluded that there was about 12,000 megawatts of technical potential, with about 4,000 megawatts economically available for 2020.

What we did in this report, we updated that number ,in light of a lot of the things that have happened over the last six years. But also we've put a little bit of a policy twist towards the economically available numbers.

So we've now got scenarios that are built in based on various policy directives that the state could take. Not to suggest that anyone is preferred at this point, but it's just a matter of trying to get a range of where we could go with different levels of policy implementation towards CHP.

And the scenarios and those implications are going to be discussed today, and you'll see a lot of that discussion and we're looking to get feedback on your initial thoughts with respect to that.

We're really trying to foster an open discussion here about market potential. So we're not necessarily looking at this as pure cost or pure benefit, we're really trying to understand it better and go from there.

So you can see the objectives. We're looking really to understand the current situation. Definitions are always difficult to deal with. Some people will look at CHP from a large standpoint and a small standpoint, and you'll see how the numbers change from point to point.

And we're trying to get a rounded view of different size technology, and also end users. And you'll see that through the course of our discussion

And you'll also get a utility perspective, and one thing we also wanted to do is bring a little bit of an international flavor into the picture. And, as Mark will probably describe in his comments, as we talk about the Eltra discussion, that they are in a position where we could see ourselves if we were very aggressive towards CHP implementation.

That is basically where we could be ten to 15 years our, and that will become evident as that discussion goes on. Also what's interesting about that presentation in particular is it does have relevance to the distribution system planning stuff that goes on, although we won't focus on that so much.

And also some of the renewable transmission issues we've dealt with throughout the course of this process.

So the agenda itself, from what's contained on the table, we've made one slight modification. We thought it would be more useful to have the utility panel react to some of the policy discussion as opposed to giving us a general feel on their perspectives on CHP, since that's fairly well voiced in numerous records, including the PUC DGOIR, which in fact is scheduled for hearings the week of May 9th.

So we thought it would be useful to move that down to later on in the day.

We're going to start off with an end user panel discussion, and Nick Lenssen, Primen and EPRI Solutions, however you want to be characterized. Nick does a great job of framing end user perspectives, and he's been involved with considerable survey information and research.

So he'll lead the discussion, which will include those that are included on the list. And I'll Let Nick introduce them.

Then we'll switch over to our international experience.

The lunch break is kind of a floating one, depending on what our time situation is. We expect that to be a good time to break for lunch, but we'll see how that goes.

And then most of the rest of the discussion will focus on the CHP assessment that's posted, the EPRI work that's done, with presentation of some of the numbers and looking at the scenario analysis, and then having some utility discussion about the treatment of the CHP as it relates to those policy options.

Before we close then we'll have a little bit of shift, and we'll look at some research that's being done by UC Irvine on emissions work with respect to the southwest air basin, which has some specific relevance towards the 2007 CARB standards for distributed generation, and some of the debate that's going on in their forum.

So with that I'm going to turn the discussion over in just a second to Nick. This is just another depiction of what I just said, if you don't like words and you like illustrations with words.

This is kind of what we're doing. End user research, market analysis, policy analysis, and then the results will come up. And you'll probably see this graphic show up with different things over the course of the day, so. If you miss it today, right now, you'll catch it again.

Again, this is just our website location for all the documentation that's contained.

With that, I'm going to turn it over to Nick. And while Nick's getting things set, if I could have those on the round table discussion for the end user panel come on up and grab a seat. No particular order, whoever's there first has first choice.

MR. LENSSEN: Thank you very much. Commissioner Geesman, Commissioner Boyd, thank you for your attention to this issue.

And I think it's great and appropriate that we start with the end users, end use customers and the representatives on this panel, because in the end CHP implies siting electric power equipment at end user sites.

And if you don't have their willingness, in fact their pursuit of expanding CHP at their sites, then you'll probably at a non-starter position initially. So you need to start with them, see what their demands are, see what their interest is, and go from there.

In terms of the context for this session, it is as Scott referred to, this arrow, this research approach that we were asked to take by the Energy Commission on evaluating the CHP potential in California. And this session really is focusing on the end users and their needs and desires.

Our approach in this study was to base findings on quite a bit of market research, national quantitative studies that we did of literally thousands of users over the past few years, as well as qualitative interviews we did with 20 energy users in California as well as three project developers.

Scott showed the website with the documentation. There is a draft report which lists not by name the companies that we talked to, but location, either northern or southern California, the type of company in terms of what sort of sector, and the general size range, the capacity of the CHP unit they either have or have evaluated and decided not to have or are still considering adopting to their use.

So I'm going to present the findings from that research, and then we're going to get a reality check from the panel, what they agree with and do not agree with I suppose, but also additional comments in terms of their experience of working with CHP, or in the case of at least one I think, examining CHP but deciding not to go forward with it.

I think that it's important, some of these top line results I'm going to mention is, first off, there's not a huge amount of end users of businesses out there who want to adopt CHP. It's a very small percentage of the business population that are real candidates for CHP.

So we shouldn't delude ourselves that there's a huge market for it, in terms of numbers.

We should also remember that when it comes down to the bottom line for CHP, well, the bottom line is what counts most. Economics. If they're going to adopt CHP the economics have to work for them, because they're not into it for a charitable or other reasons, typically.

Surprisingly, in some accounts reliability is a very important issue for many energy users too, in terms of whether they adopt CHP or not.

Economics is the driver, but it's also the principle barrier. If the economics don't work, then the CHP isn't adopted. But there's also numerous non-economic barriers to adoption that exist.

Lastly, the main portion of my presentation will focus on some policy options that energy users say they want in order to have a more favorable playing field to pursue CHP.

Those policies tend to focus, again, on the economic issue. How can we make economics work better for CHP?

Quickly, turning to some of the quantitative data, in our national and then comparing national to California's data, when I say there's a small percentage of customers out there, of energy users who are interested in CHP, this is what I was referring to.

If we look at, nationally, all of the energy users with a demand between 100 kilowatts and 10 megawatts -- unfortunately we didn't go above the 10 megawatts in this survey work -- in 2003 we would classify only two percent of those users as strong prospects.

And when we say strong prospects we say that we mean that they rate themselves as likely to adopt distributive generation, not just the CHP, but distributive generation within the next two years, and they are actively evaluating their options. It's not just some idea out there, but they're actually examining it.

If you get just the people who say "oh, I think this is something we might adopt" that number goes up to 13 percent total. But nationwide there's only about 12,000 businesses, as of two years ago, that are looking at this. Fortunately we're in the field updating this survey right now, this data.

We've looked at it over time and we've seen the movement. Back in 2001, during the western power crisis there was nearly a quarter of all energy users who were prospects, of which more than 15 percent were actively evaluating distributive generation options.

That disappeared with the recession and the alleviation of the power crisis, and started growing again in 2003. And I expect in 2005 we'll have numbers fairly similar to 2003, though likely there will be some surprises in there.

In other words, it's a changing status in terms of what energy users are looking at, at a point of time.

These data illustrate the fact that saving money on energy and more reliable power are the two biggest issues. Interestingly too, the third issue, greater predictability of energy prices.

If there's one thing energy users want, what we've found in survey after survey, is they want to be able to budget their energy costs, like they can budget almost every other input into their operation.

And again there's some other reasons there that some people mentioned, including capturing waste heat for use. But on the whole they don't want to, energy users don't want to cogenerate because they want to cogenerate, they want to cogenerate to save money.

I have peppered throughout the presentation quotes from our interviews. I'm not going to read them in the interest of saving time, but they are in the handouts available in the back table as well as on the website.

Boring down a little bit more, in terms of the data. We see in California, the blue line here, that the percentage of establishments that would find a payback acceptable for distributed generation or distributed energy doesn't really vary from the national average.

But what's important about this slide, if you look at the two year level, less than 50 percent of energy users are willing to pursue a DG project if the payback is only two years.

Only two years, two years is an incredible internal rate of return, it's greater than 50 percent, but energy users aren't willing to invest that money in that, on the whole.

So as the economics get more difficult, the willingness of energy users to participate declines.

And of course you do have different payback acceptance by different sectors and business types. Not surprisingly, the government and education, the public sector, is much more willing to accept a longer payback than, say, fiercely competitive wholesale or retail industries. You get the manufacturing and some other industries in between.

We found little difference in the payback acceptance by facility size, which is surprising to me because I would think that larger energy users would be more willing to accept longer payback, but our research on the whole shows that's not true.

But it's important to mention that it takes more than just savings for a CHP or a distributive generation deal to take place. There's a whole host of other issues. Those are pre-existing for CHP to be considered, for a project to actually be adopted by energy users.

You need a whole host of other issues to be addressed, and that includes specific host sites, the company's financial position, or the general state of the economy.

In terms of the financial position, I'll mention it's whether that company is expanding its operations, whether it wants to make a commitment to stay in that particular site or state, or whether that company is on the downside of their growth curve.

Financing can be important at times for some companies, for others not. Warranties and guarantees, how the deal gets drawn out, and the service agreement. Support for environmental and other permitting issues. And the relationship with the local utilities provider, in terms of interconnection, buyback, and other status.

These are all issues that con disrupt and trip up a potential CHP project. And I imagine everyone on this table has handfuls of examples where you thought you had a project going and something happened along the way, and it didn't happen.

The second part of our research really focused on the in-depth interviews, talking with energy users in California. And again, they're all listed in the reports.

Some of the barriers that they mentioned to us. I would say unprovoked in a sense, we didn't read them a list and say "are these barriers", we asked them to identify the barriers themselves.

Again, confirming what we've heard in

quantitative studies of national and California users, these interviewees started with "it's just not cost-effective."

Between the capital costs, the natural gas prices, the interconnection fees -- exit fees I don't have written here which is mentioned in the case -- it's just challenging to make the economics work out.

We also heard quite a, and surprisingly, many times, that it's a low priority from upper management. Energy in general is a low priority, despite the western power crisis of 2000-2001, and despite the current high prices of natural gas and electricity.

Without it being a priority you can't get their attention to sign off on a deal and commit capital. It's not the core business of energy users. We've been through a generation now of outsourced, non-core operation of companies, and energy has kind of been on the side of moving out and staying in.

Why does most energy users, you know, refineries are an exception I would say, but most energy users aren't in the energy business. They're in the business of selling something or producing something, and energy is just an input for them.

They don't want to take the risk of becoming an energy producer, because there is a real risk involved for them most times.

And then again, the uncertainty of the marketplace, where are prices heading, how will policies change? Fortunately and unfortunately, California has had a history of very activist policy making and a change in the ground rules, and that becomes very confusing for energy users.

In fact, I was sharing one example this morning of, with all the exit fee exemptions and system benefit charges and all these different fees, one user couldn't figure out what it would cost him to go co-generate or use CHP versus staying on the grid.

He just kind of threw up his hands in despair and said "I'm not even going to try and figure it out." That complexity obviously can be a greatly frustrating experience, but again, at the same time, the policies can also create the incentives to create the change and the adoption of CHP.

When we asked energy users specifically

to name one thing, if the government of California could do one thing to encourage CHP, what would it be?

Well, the respondents universally preferred policies that would improve the overall economics of CHP. And some of the specifics, the two specifics we heard the most from them were increase the south generation incentive program caps to allow larger projects to reap the benefits of the incentive programs, as well as increase the incentive level for that part of the project that would actually get the rebate.

We also heard a lot about net metering, which again was fairly surprising since net metering today is limited to renewables, principally photovoltaics and in small wind, I guess up to a megawatt with the photovoltaics today.

Obviously those two policies would be very costly for the state, to expand to that level, but this is what we were told, and this is what the users came up with first.

Most respondents did not see value in initiatives that helped with project planning, the project planning phase, since we had some other options that would ask folks about those areas as well. And I'll get into more detail on some of these responses.

A couple of pages of quotes again that I will not read through. One is a small community college district, just a one megawatt non-adopter, I mean, and a hospital six megawatt non-adopter. Again, I think the non-adopter people are very important to listen to, because they were looking at it, they were considering it, but for some reason or another they decided not to pursue CHP.

Likewise, net metering, a printing company, a 4.2 megawatt non-adopter, and in this community college district again, I think it was the same one.

There were a number of other initiatives to support CHP that users would support, but again they really centered on economic issues. And again, this afternoon, Snuller from E3 will talk more about the policies so I'm not going to get into the details too much now for the sake of time and letting our panel speak.

But being able to get a credit on the bill for the wholesale price of power produced onsite, and elimination of exit fees.

Natural gas purchasing, whether forward price or expanding the current state discount that already exists in terms of the programs.

We're back to exit fees again. I know you don't want to hear about exit fees, but that's what the energy users brought up, they're not letting that dog lie, still.

And lastly, perhaps, a state tax credit.

But one thing we did hear underlying all the recommendations from energy users was simplicity. It's already too complex, they want it more simple.

There were some initiatives that we brought up to user that were not favored, that were not grabbed on to by them. They didn't really, you know, finding a vendor or project developer an issue.

There's plenty of people I suppose out on the street trying to sell them right now, but they did support a list, whether a certification list from the Commission or a utility list of pre-approved, you know, companies that are real, that are around, that are bonded to certain amounts, as opposed to just the fly-by-night operators.

Which has had quite a few people in the

CHP industry come in and go out, and you need stability from a user perspective that the company will be there.

Financing wasn't a problem for most energy users, but they're not going to say no to favorable rates in terms of financing, whether it's state or some other mechanism.

And lastly, the issue of permitting came up, which we really had diametrically opposed views on this at times. Some folks said permitting was a problem, it was an issue, and not just emissions but interconnections as well, and land use permitting issues, local ones.

That it is a problem, but it isn't a deciding factor. They would appreciate a faster permitting process, some more streamlining, but in the end we didn't have users say that permitting killed projects.

Now I'm very aware that permitting probably has killed projects in some cases, for air emissions regulations or other issues. But we didn't find that in our research, which was interesting. I think we perhaps expected to find that more going into it.

Moving towards the wrap-up here before

we open up the panel, what are some of the implications for the California market that we pulled away from this?

First off, again, CHP sales and adoption is not an easy task and you face, you know, very large challenges to increase the CHP capacITy in the state, perhaps much more now than you did back in the 1970's with the oil crisis.

Again, less than half of energy users say a two year payback is acceptable. They need faster payback to expand that market. But, beyond payback, other issues can derail CHP projects.

And lastly, the marketing policy gyrations of the past decade in California has really led to less CHP than anticipated. Sometimes that's been, the market gyrations hasn't been in your control, the natural gas prices for example.

But there is a higher risk perception on the part of energy users from pursuing CHP, just not knowing what the next ten years are going to bring.

Users in the public sector have a much lower payback requirement than those in the private sector, and lastly it looks like enacting the right policies that can tip a prospect to adopting CHP is crucial, otherwise the market will chug along at a low level with piecemeal adoption rather than real expansion.

And our interviews found that the priority on the part of energy users are the economic ones.

With that I'd like to turn to our panel. I believe our panel was asked to give comments in the five to ten minute range, Mark?

MR. RAWSON: Yes.

MR. LENSSEN: Your experience and your views on CHP adoption, what's worked well, what could work better. Please if you have disagreement with our findings I think that's important to hear as well.

But what we'll probably do is go right down the line, and what I'd like to do is actually introduce each person now, and then we can head down the line.

Let's start with Richard Brent, who is the Director of Government Affairs from Solar Turbine; and then we'll have David Dyck, who is the Director of Energy Contracts and Strategy at Valero Energy Corporation;

next Ed Yates, who is the President and CEO and the Secretary of the California League of Food Processors, and he's representing I would say more small energy users, more dispersed, as opposed to the refinery setting;

then Ralph Renne, who is the Director of Facilities at Exar Corporation, who will bring us kind of the high tech view;

and lastly Michael Alcantar, who is the General Counsel for the Cogeneration Association of California, and they also have some comments on the back table as well.

With that, if I can ask Richard Brent to offer five to ten minutes of comments first, and I'll wave at you when your time's up.

MR. BRENT: Thank you, Nick. Commissioners, staff, thank you for hosting this and bringing this opportunity forward for public discussion in the workshop.

We are a manufacturer of small, industrial gas turbine engines. The largest single sized unit we sell is 15 megawatts, the smallest is 1 1/2 megawatts. We carry about 65 percent of the industry's shipments worldwide on this size class of industrial product.

Predominately used for compression in the gas industry, and used in combined heat and power in over 90 countries.

From the perspective of an end user, we're a San Diego-based company. We have two facilities in that county, where we work with our service provider, San Diego Gas and Electric, and we have one facility in Los Angeles, where we work with LADWP.

I would say by virtue of the temperature and the lack of need for process steam we are not necessarily a candidate for combined heat and power, and what we would call the base case of opportunity here in the state of California.

But given the right sort of encouragement I suspect we would build infrastructure to take out the air conditioning system that today is electric drive and go into more of a combined cooling, heating and power where hot water, chilled water and where necessary domestic kind of quality steam could be utilized.

As I said, we've not done that to date. We are a user of distributive generation. We do it actually at a test site for a number of air permitting and utility contractual arrangements.

We generally buy the gas, and what electricity we don't need we give back to SDG&E, and I want to underscore the word "give back."

A couple of points to Nick's presentation. I find no fault with what he has said, all of that's true. Getting a return on investment when there's uncertainly in the tariffs and the rate structures on the perception of the end user is very difficult, and no different for us as well.

And yet at the same time I'm reminded of one pharma-chemical company talked about buying combined heat and power as high as 55 cents a kilowatt hour as a deferral, and when asked by the then Assistant Secretary of Energy for the Department of Energy why he would spend that much money when the average rig was ten cents he said "do you know what it's like to lose a batch of recombinant DNA?"

And that leads to a point that maybe didn't come up with as great a deal of clarity. All of us are concerned about reliability. We're concerned about reliability because it affects our productivity.

And as our productivity gets affected,

ad we are trying to get out of an economic slump and increase our production, unreliable power can have a great deal of play on the cost of our product and the uncertainty of scheduled delivery of our product.

So we try to monetize reliability, and we try to look for stability of cost. Many times, when the customer says "I don't know what my energy cost is going to be", there's a lot of uncertainty.

And we remind them from our friends in the retail gas industry, the natural gas industry, which is the predominate fuel for at least our type of CHP, that they can buy ten year contracts.

They may pay a little bit higher than market price today, but they're surety of supply and surety of cost, which, when yo maintain your equipment properly, means you have surety of electric rate -- if you want to call it rate, or price or cost, pick your words -- for ten years. You can buy 80 percent of your gas, you can hedge the rest.

There are lots of different plays that can be used, but to Nick's point, most of the customers are not in the energy business. They're in what I like to call the chakra business, and all they want is that black box that always works, and makes energy for them, not just electricity but energy for them, at a stable price that they can count on for a long enough period of time to factor in to the cost of making their widgets.

I'll close off by saving that we find some customers are interested in building more generation than what the thermal load requires, and then putting that generation back into the grid.

We find, for example, in other parts of this country, wherever you have a wholesale pool, the wholesale pool is ready in its acceptance of small scale generation, and they have interconnection procedures that are rather carefully laid out, that is fair and non-discriminatory and reasonable in terms of cost and schedule for all the parties involved.

But to get through the local utility distribution company, to be able to work into the wholesale market opportunity for even just capacity has been extremely difficult.

The uncertainty amongst the utility distribution companies has made uncertainty about combined heat and power providing opportunity into the wholesale market if nothing else for capacity and demand reduction.

I can stop there, Nick, or continue?

MR. LENSSEN: I think that'd be great to start, Richard, and we'll make sure we come back to folks afterwards. David Dyck from Valero?

MR. DYCK: Good morning, thanks for having me. Valero Energy Corp has about 700 megawatts of connected load in North America, spread across about NERC regions. And of that 700 megawatts about 130 is self-generated, cogenerated power.

Valero responded to Governor Davis' call for more resources in early 2001. The government at that time put in place and implemented an expedited permitting process and we were very pleased with the outcome. It was originally supposed to be within six months, but we got it in nine months, and we're not going to quibble, it went pretty well.

I would say though that, you know, given the size of the typical cogen units that are going in today you're still talking about costs for permitting that are pretty high, relative to the amount of power that you produce. So there isn't a lot of scale of economy associated with these smaller units.

Our experience, somewhat went downhill in terms of interconnection. We found this to be quite an obstacle. Our unit can access to the grid, unlike some smaller distributive generation units that generally just cover a portion of a site's load.

And what we found was that, you know, the ISO felt that we had to interconnect with them, and that we had to comply with the ISO tariff.

And the ISO tariff, if you haven't seen it, it's an enormous document. Compliance issues are very significant. And for somebody who's got, you know, just a few megawatts that's going to be sent out to the grid, it's really a byproduct kind of situation. And we don't, it's not our main business.

So the result of that was that we're in a sort of regulatory limbo right now. We can't access to the grid because we're not part of the ISO system. On the other hand, PG&E, our local utility, won't take our power unless we sign a master services agreement for metering with the ISO.

So we're in sort of a purgatory situation. We can't operate our unit at full rate. So at the moment we're sub-optimal in terms of operation. And it's kind of odd, because most of the precedents at FERC on how this jurisdictional treatment should be applied to our unit were all established in California.

And we've been able to, you know, use these same arguments, these same precedents at the FERC to get a very good outcome in New Jersey. But at the moment we can't access to the grid.

We've been trying to put in place a small power sales agreement with PG&E for over a year, and we're stuck in this Catch 22. They want us to be ISO complaint, and in fact we have ISO compliant meters. But it doesn't matter. We're just kind of stuck.

We want to build a second unit, in fact we've got a second unit permitted. We've got the space there, the plot is there, it's empty, waiting for a second turbine. But at the moment we're stuck in this regulatory limbo.

MR. LENSSEN: If I could take a quick

moderator's prerogative, I'm curious, it sounds like the cost of ISO compliance would be more than the value of the megawatts exported?

MR. DYCK: Absolutely, yes. Exactly. And the other fact is that, you know, in PURPA we should be able to get standby service from the regulatory, or from the local utility, and we can't even get that -- well, we do have a standby service, but if we went to the ISO connection we would not.

COMMISSIONER GEESMAN: What have you been able to accomplish in New Jersey?

MR. DYCK: Well, exactly what we wanted, and exactly what the FERC precedents have established, that we should be able to connect with our local utility under a state jurisdictional setup. We shouldn't have to have a relationship with the ISO.

The local utility should be the interface between us and the ISO. And, you know, it's working fine in PJM.

MR. LENSSEN: You might want to point out you can't even comply with the ISO tariff.

MR. DYCK: Yeah, compliance with the ISO tariff, you're never quite sure if you're there or

not. It reminds of the U2 song, where Bono says "it's everything I wish I never knew."
(laughter)

MR. LENSSEN: Thank you. Do you have more comments now, David or --?

MR. DYCK: Well, I guess I'd like to take one minute to talk about LADWP, and their recent implementation of a tariff there which, you know, the rhetoric around this was "this is helpful and supportive of cogeneration."

But the fact of the matter is that tariff ends up forcing us to pay transmission costs every month whether we're using the transmission grid or not. And it's basically a cogen killer rate.

And if there's some way of getting a policy in place that provides some uniformity in terms of how the tariffs are applied for supporting cogeneration, that would be excellent.

We're looking at a turbine there, but it's dead in the water because of that tariff.

MR. LENSSEN: Thanks, David. Next we have Ed Yates from the California League of Food Processors.

MR. YATES: Thank you. Good morning.

Commissioners, I appreciate the opportunity to come share some thoughts about CHP. I generally agree with everything Nick said in terms of barriers and those sorts of things.

A little word. The California League of Food Processors represents the fruit and vegetable industry in California. We do not represent the other sectors, like bakeries, meat, beverages and so forth.

As such, the fruit and vegetable sector accounts for about 30 percent of the economic activity in the food processor industry, but 60 percent of the energy.

They use about the same amount of energy as they did 30 years ago, about 350 million therms of natural gas. But they're putting twice as much food through those facilities, so in essence they've cut their energy use in half.

If they were operating year-round, they would be using some 2 billion therms of natural gas. The assessment report indicates a high load factor customer versus a low load factor customer. A low load factor customer is defined as somewhere between 3,500 and 5,000.

A fruit and vegetable processor, due to

the fact that they only operate when those delicious fruits and vegetables produced in California are ripe and available, some 1,600 to 2,200 hours. That is probably the biggest barrier to further deployment of cogen in the industry.

Now, it would be my humble opinion that the numbers that show up for food processing are probably a pretty saturated number, that's about all you're going to really get.

Again, a number of the factors, the barriers that were discussed they process food, and they do it better than anybody in the world. And there's not a whole lot of interest in getting into the energy business.

And when they reflect upon the experiences of those who have gotten in to the cogen business, that experience is not encouraging to dive off that diving board.

My limited understanding, most of the League members that were in the cogen business are no longer operating their own facilities. Private power companies bought 'em up.

In other situations, six, eight years ago, we had a high level of interest in biomass cogeneration. Again, a unnamed utility bought 'em up, and eliminated their home for their biomass and they had to find other places.

It is a hostile environment out there, and food processors recognize that, and they want to stick to their business.

I don't know what else I can say, except at least from the fruit and vegetable sector, and this has been looked at a number of times over the last 30 years, it's very simple, when you operate a facility that only utilizes it's capacity 15 percent of the time it makes the economic hurdle very high.

There is a lot of interest, but frankly a cogeneration unit spinning in December wouldn't be much good, I think. And with that, I am brief.

MR. LENSSEN: Great. If I could just ask one question of you, Mr. Yates. And that is that yo mentioned that some of the existing CHP facilities at some of your companies that are part of the League, the sites have been brought up by private power companies.

I would see that perhaps as reducing the risk for your members. That is, those companies that are buying at the sites are still delivering steam to your facilities that are taking on the operational risk.

Is that perhaps a better model for the food processing sector? That in fact it's third party ownership rather than direct ownership, with their own capital at risk?

MR. YATES: Well, certainly. Because it does reduce the risk, and they do need the steam. ?And all those barriers -- I would presume to venture to guess that there would be a lot more if there were an effective, easy net metering.

Most of the prospects for CHP are those that operate more year-round. 80 percent of the energy that fruit and vegetable sector consumes is that 70 to 90 day season. But there's still 20 percent that's consumed on a more year-round basis, and those are the more likely prospects.

As mentioned earlier, the complexity and the -- I'll say again -- the hostile environment that one has to operate under with not only the regulations but IOU's, they're not interested, in my view, in really cooperating and promoting a diversity of electric supply.

The other thing, why you shouldn't look to the food processing industry very much, is there continues to be an ongoing economic shakeout. We see consolidations, we see mergers, the industry's interest is to become the most efficient producers in the world, because that's who they're competing with.

So, I hope that responds to your question. There is some interest particularly in southern California with some of the smaller, less than a megawatt, who are using turbines and capturing not only the waste heat but generate some electricity in-house, but they're very, very small. They're not connected to the grid.

They're just satisfying not only some increment of their load, but certainly providing some sort of security factor, given the relatively poor quality of electric power in the state. Processors can count on being interrupted two or three times a season. Very poor power quality.

MS. JONES: Can I ask you about the timing of those loads during the year. is it primarily summer, early fall?

MR. YATES: It's primarily mid-July through mid-October.

MS. JONES: Okay, so that coincides fairly well with peak loads in the summer, when we need additional power.

MR. YATES: That is correct.
MS. JONES: Thank you.
MR. LENSSEN: Thank you very much, Mr. Yates. Next is Ralph Renne, Exar Corporation.
MR. RENNE: Thank you, Commissioner Geesman and Commissioner Boyd. I appreciate being invited. And Scott for sending me an e-mail to come and join here today.
Nick, I basically concur with everything you presented on your survey. I found you kind of just reiterated the process that we experienced in trying to implement this.
Basically, Exar Corporation is a small semi-conductor company in Silicon Valley. We used to be a full wafer processing facility and as most of the valley no longer processes silicon, we have done that very similarly and we're considered a fabric company.
So we outsource the majority of process, but we do run sort of a back end process, about 10,000 square feet of production within the facility, so the remainder of the facility is just predominately R&D space and office.
So we would be sort of the atypical cogen implementer if you will, or not necessarily

the ideal candidate. We did have a relatively high thermal load due to the environmental conditions we have to maintain in the process area, so aside from that we are not necessarily a good profile for cogen.

What really prompted this and got us to re-examine, back in the fab days I had looked at cogeneration as early as 1989, and then second when we developed our campus site in '95 we had seriously looked at cogeneration at that time.

It just, as Nick's survey pointed out, was really not core to our business. Technology was not as good as it is today, and particular in controls, and it was a tough buy-in.

I think our economics were better at the time since we were at higher loads and had more thermal needs, but nonetheless, what got this thing to be revisited was, I believe it was January 17th of 2001 we were one of the first people that suffered the rotating block outages.

This took us for about two and a half hours, right in the middle of the day. But one of the things that is core to our business today is we run a development, product development predominately on a server farm, so we'll do ten or

15 lead characterizations on the cloister or multiple sets of computers.

If that gets interrupted we basically start the process over. So there is a requirement for premium power, reliable power relative to that particular component of R&D.

At that moment in time we came very close to running out of UPS battery. It prompted management to say, look, how could us and facilities prevent this? And we came back and said you can apply money in the form of backup generation.

Once we got all the stakeholders together the data center backed up generation for about 250, 300 KW grew to a complete cyclite backup generation of about a megawatt, and then it became an issue of how are you going to ride through the transition.

So, a seven second lag was not acceptable, they kind of wanted to see how can we get premium power. We were talking about potentially getting UPS to ride through the generation startup time, and very quickly approached well over a million dollars for that installation.

What then I was able to do is basically talk to the -- and again this is I think one of the opportunities -- in my position I was able to move this through executive management because I report to the CFO and I had his ear available for considerable amounts of time.

So as I was going through all this analysis I basically presented to him how he could buy his backup power within the existing energy budget.

And that's really what cogeneration offered to us, the fact that we could buy premium or backup infrastructure within the existing energy budget. Effectively it was a capital expenditure of about three and a half, where we qualified for the 30 percent rebate, so i think it was about net 2.6 or so. I've got a check from PG&E for $926,000.

So that really was one of the economic benefits that the self-generation incentive program gave to us, is really cross that threshold of return on investment. Now this is really atypical to most of the survey.

We were approaching about six years for the ROI. This is, you know, far greater than that two year threshold that a lot of people did.

But if you take this project and present it to management that it simply a rate of return we can offer them greater than the investments than they presently have, it really kind of took it out of this poor -- sort of, all the paradigms broke down once you overcome the issue of it's not my core business, we'd rather buy power from the utility, where do we have the resources to engage in this type of a project.

All those obstacles can really be overcome very quickly if you just simply quantify this into a financial term, what is the rate of return we can provide you with your money compared to what your doing.

So, and basically Exar is a very cash-strong company, and I think this is one of the advantages we have. We have a lot of cash sitting around in very low yield investments, and today a 1.75 or 2 percent is probably good for a conservative investment. We are being able to present this project with a rate of return at about 8 to 10 percent depending on the natural gas price or whatever you pick for natural gas.

So there's sort of the way to package it and get over the hurdles of, it's not even the technology, it's just simply an investment, a rate of return. But nonetheless it did not cost then an expense increase.

It effectively reduced expenses, increased assets, and the net of it we realized a savings greater than 15 percent, which was our objective. We're challenged with that now, given the price of natural gas.

But that was fundamentally sort of the corporate -- I guess the process really is you've got to have a reason, you have to have an objective, you do that to have engineering feasibility, you have to have proximity, waste heat recovery in our case.

We used it for comfort heating as well as process heating and supplementing our boiler loads for our hot water system as opposed to steam.

And then we used the remaining hot water to run an absorption system. So basically we're satisfying comfort heating, when the heating demand is up in the morning. As that declines, the inverse relationship with the cooling demand increases, and then we divert the hot water and supplement our cooling.

So there is basically an opportunity to use this cogeneration system and supplement about 200 tons of chill water as our base HVAC load, and then use the electric chillers to basically take the demand above that.

So there is some substantial economic benefits just from not running electric chillers. And then if you factor in the efficiency of electric chillers you find that there is a more compelling economic return than a lot of -- in fact, our, the general contractor that packaged this together didn't really factor in that one component, which really does give you a couple more percentages toward that return.

So there is some benefit that internal guys can do in their own analysis that the industry doesn't necessarily provide yet.

The reliability and economics, it was one of the compelling issues, but really our biggest challenge at the moment is procurement. So what transformed my position as a typical facilities manager type who's familiar with HVAC and building infrastructure and electrical distribution.

Now I have a job as sort of a professional procurement. And this is really taking us out of our realm of comfort and expertise. And I actually tried to get finance, our cash manager to invest all our cash and throughout the world, and tried to get him to take that role, and he did not.

He pushed it right back to my plate. So right now I'm trying to figure out how to be a commodity trader, which is completely foreign to what I've been doing. Although I've been tracking the market and I can tell you more about natural gas in the last two years than I care to know myself.

Really, from an implementation standpoint, all of that follows under regulatory challenges. I was listening to Dick and the struggles with interconnection, and we ran into some of those issues.

But first and foremost, the rebate at the time we applied stipulated, or at least the interpretation by PG&E was that your load that qualifies for cogen or the rebate amount was basically that peak demand or peak load that you had in the 12 trailing months.

So that's how we ended up with this strange size of 926 KW. We have two 463 units that I de-rated from a standard Caterpillar 3508 package, which is a 505 KW machine, we had Caterpillar de-rate down to 463 to meet this rebate compliance issue.

Now, standard design would say I should have 20 percent head room. NEC says everything is 80 percent. So we initially specked out two 600's with about a 900 or about a one megawatt load. We were thinking that would give us 20 percent head room, but because of the rebate we changed from two 600's down to two 463's.

What was really on the regulatory side the biggest impact to me was the air district, at the time that we submitted our application, and this was spring of 2002, about March, the standards in the Bay Area Quality Management District was .5 grams per brake horsepower NOX.

We went through the initial what they call back assessment, we came through what they call a health risk assessment, and go back for the final back review -- and I read the language coming out of AB 970. It said the air district would do an express 20 day review, and if they can't do it they were supposed to outsource it.

I was complaining about June to the project team where's my air district permit? And three months into the process we weren't getting feedback, which was very concerning.

We finally got the word back that they had decided to adopt .15 grams per brake horsepower, and made it retroactive to all applications in the process.

So the impact here, we selected specifically a 3508 LE model, which is designed for the European community. It was a 50 hertz motor that I had put on a transmission to get it back up to 60 hertz, but out of the box, without any abatement equipment, it met that compliance. That got thrown out the door.

The impact really was about 20 percent of the project cost. We were less than 3 million at that time. It obviously took me about 3 million or close to 3.6.

And here's a big, real, kind of contractual issue. Ours was predominately a design build. We went through months and months of negotiation with our design build contractor. They wanted a contingency of 20 percent.

We were trying to ask them well, why can't we define the project, what's the contingency amount, that's a substantial amount of money, and it just seems like I'm going to give you a check to go cover your overages.

So we negotiated the ambiguity or uncertainty result revolved around the regulatory environment. So we basically in our contract terms said okay, any construction-related or non-regulatory issue we cap that contingency to about two percent.

We move forward, got it through the legal process, and all the regulatory risk fell on my side of the table. Well, unfortunately we realized and paid for that regulatory risk.

So, this is about 4 months into the project, and I had to go back to top management. And my boss was smart enough to have me do the presentation to the board of directors, so --.

My head's in the guillotine, why did I even advocate this thing? I really had a great job, and I didn't need to put my head in the noose, and I have kids going to college, and it's just not a good tie to be begging for, you know, $600,000.

Nonetheless, I explained it management and again, I think just by virtue of reporting to the CFO, he was very intimate in the entire project, he was very active and engaged.

I mean, he was aware of every nitty gritty detail, so given that situation, and given that he's a finance guy, he just simply calculated the impact to his rate of return and the impact to his rate of depreciation and said okay, well, we'll be good guys and not cancel the project.

I was prepared to take a $300,000 charge and return all the equipment and try to overcome that debacle, but nonetheless he approved going forward. Aside from the impact in terms of costs it was about a five month delay in the project installation.

So there's some impact to your rate of return just when you think you're going to turn the project on. We were thinking August at that time and it got pushed back and we didn't come online until January.

But that was really sort of on the implementation side. The regulatory environment was very tough to overcome, particularly with the air district. The Rule 21 was also a situation where we just did not want to go into the ambiguity of an interconnection study.

And just for expediency we decided not to do it. There's basically three interconnection options that are provided to you, at least in PG&E territory, which was the standard Rule 21, you have reverse power relay settings; the interconnection, what they call Rule 21 with inadvertent export; and then basically, effectively a merchant generator like a QF facility, where you're an exporting facility.

We basically wanted to be completely load following, so the inadvertent exporting was really what we were after. Unfortunately I think, because we didn't want to go through the 3 to 6 month delay of an interconnection study, we decided not to do that, and just went forward with the standard Rule 21.

Now, what that meant to us was really some technical challenges. I basically got a system that can completely support my load, we're completely load following, but due to the reverse power relay requirement on Rule 21 we had to import somewhere about 75 KW just to maintain system stability.

Here's, 75 KW itself represents somewhere about 50,000 a year, if you're in PG&E territory. That was not necessarily planned into the original economics.

So that made the project obviously a little less attractive, obviously taking a little more expense on the capital cost makes it a little less attractive also.

A lot of ambiguity going in because, again, we took on all the regulatory risk, the departing load question was still looming large at that time, and we were really banking on the fact that the one megawatt threshold kind of exempted, and it still held true pretty much to today that one megawatt still fell below most all of the exemptions, so we do not have any departing load obligation.

We;re exempted from the standby fee, at least until 2011 or sometime, I think it was a ten year decision at that time. But again, that's still caused concern.

Once you get the system going the's operational challenges, and that's really where i'd like to spend just a few moments. As sort of a system owner/operator I can now feel for the utilities when they say they have outages.

I can understand how and why they have them, and these are equipment that, you know, we hope they were a little more reliable, but like any moving component there's a slew of maintenance and reliability issues that we seem to be challenged with continuously.

And we have obscure things like an exciter coil go out, where nobody has such a thing ever happen, well it happened to me. It's hard to explain to management why I have some interruptions.

We've managed to knock out the buildings a couple of times. so we've had our share of running the system, and particularly in island mode natural gas systems just don't respond like backup generator systems. If you've got large load variations it really does impact you significantly in terms of power quality, you'll have some frequency deviations.

But nonetheless, the economics in terms of unplanned outages, taking on demand charges when you don't forecast them has proved to be more challenging than I had originally thought or I think I was a lot more optimistic than I am today.

But still, meeting the bottom line economic objective of 15 percent, we've managed to do so. And given the situation with natural gas today, I think the only benefit is the fact that we did have enough of a heat rate or a heat load that would have correlated.

Right now we consume about 550,000 therms annually. And I used to consume about 220, prior to the cogen. So even though I'm using twice as much fuel, one of the benefits of the cogen system in particular, and the was someone who asked for discount gas, well, we do get it in the form of a discount transport charge.

The GEG tariff is about one-tenth the cost of the GMT tariff. So the net gas on my side, when I buy from index or if we have contract on the fixed price, is really a premium on top of an index plus the transport charge.

Compared to what I would have paid under a GNR 1, just a standard PG&E tariff, you're looking at over $10 an MMBTU, or $1.05 a therm, which inherently is the offsetting benefit in terms of maintaining our return on investment.

So we've been fortunate that, albeit

natural gas has completely skewed the assumptions because of the correlation to what would have otherwise been applicable cost, we've managed to still sustain the return on investment.

One other particular note. I did find, SARBOX came up as an issue, and I did have an opportunity to say that, because of our cogeneration issue -- well, they come through and do a sort of an assessment to your vulnerability to the integrity of data, and mind you they're talking about the integrity of the reporting of that financial data, but the survey questions still come down to what kind of infrastructure, what kind of backup, and it's just an inquisition like you would not believe.

It did indeed come up, and we were able to show that we have sort of a redundant infrastructure, N+2 type reliability in our computer rooms as a result of the cogen system. So there was one conciliatory benefit to that.

But that basically gives you my experience.

MR. LENSSEN: Thank you very much, Ralph. One thing that you said that was very interesting that I pulled from your presentation was the risk factor for an energy manager to become the advocate for a CHP project.

The going in before the board meeting and now with the operational. In retrospect you'd probably say it would have been easier to just ignore the whole thing, just buy a standby and, you know, not worry about it.

But there's obviously a personal risk that an energy user takes on when they become an advocate for such a project.

MR. RENNE: Yeah, without question. I think a lot of these projects would probably never move forward within an organization because it is, I think someone mentioned, really not core to our business.

So, to convince management to go down and produce your own energy is really a tough road without some internal champion, and having access to some high enough level of management to move it forward. It's so easy to get it shut down by someone saying "it's not our core business" and then that's as far as it ever would move.

I got that resistance and sort of pushed and pushed and pushed.

MR. LENSSEN: Right. We've got one more

speaker before we open it up to public Q&A, and that's Michael Alcantar from the Cogeneration Council of California, and also representing the Energy Producers and Users Coalition. Five minutes please.

MR. ALCANTAR: Yeah, I'll try. It's clear that Exar Corporation has a person who not only knows the cogeneration forest, the trees, but a lot of the bark and the leaves, so I congratulate him on what he has unfortunately suffered through.

I'd like to say that when I was about a 12 year old lawyer I was here with Commissioners Boyd and Geesman also advocating issues associated with cogeneration project development and siting.

It would be a lie, but in the late 80's I was here trying to get permits and ultimately succeeded in getting permits for four of the single largest producers in this state. That's Watson Cogeneration Company, KRCC, Sycamore and Midway Sunset.

CAC represents those groups, Cogeneration Association of California, as well as a series of other PG&E-located enhanced or recovery-related facilities. The total generation represented just by that group approaches something along the lines of 1,800 megawatts.

If you add in the EPUC members, who include to my right David Dyck of Valero, but basically all of the western petroleum association operators who are self-generating, there's another 400 to 500 megawatts serving loads at refineries in enhanced oil fields moving gas in those generations as well.

If I could be critical in one way about the report that was done is it's wonderfully focused on looking at 10 megawatt plants into the future, it's horribly deficient in worrying about existing facilities, and what about big existing facilities.

And so I thank all of you for allowing us to be here and addressing that issue, because I think it is much more fundamental to the immediate future of California's capability of sustaining operations in this state then a number of the things we're perhaps addressing here in terms of new operations.

The reason I say that is those four large cogeneration companies I just mentioned to you come to the end of their contract life this year, next year, the year after that and the year after that. That's 1,200 megawatts. Where's it going to come from? Where's it going to be?

Are those units going to keep going and operating? And I think many of the issues you've identified from a business standpoint, nobody wants to continue to invest in a project when the regulatory uncertainty, when the stability of that operation in this environment, in this community, in this state, is no longer secure, and certainly the recovery of assets that are going to be embedded.

I want to talk about two particular case studies, one Watson and one Midset Cogeneration Company. Within our population two at somewhat opposite ends of the profile.

Watson is almost, well at 410 megawatt capacity facility, services the BP refinery in Los Angeles, Carson, California. It is the powerhouse between 20 percent of the gasoline sold in this state, a highly controversial issue at this point in life.

The surplus power from this facility alone serves in excess of 300 households, almost 350,000 households, excuse me I almost left out the three zeros.

This is a huge facility, and it has been an absolutely stellar performer. It has been online come hell or high water during the course of its operation and it continues to be. And it's just one of the four that has the same operating profile within our group.

They have not only been reliable an delivered consistent with their contracts but they have continued to do so in the face of not being paid during the energy crisis, in the face of extraordinary operating conditions, requirements and demands, and they continue to do so today.

They want to continue to do that for this state, for themselves of course, they have their own self-interest, but for the state as well.

Those contracts, those projects, are at substantial risk. Let me move to the -- let me say one other thing about Watson. There was $300 million of capital investment that built that plant. Every five years they go through a major maintenance, every one of these plants does.

They go through a major maintenance that basically rebuilds the plant, enhances its reliabilities, ensures its delivery of power.

Now, are they doing that solely for the sale of electricity? NO, they're doing it because they want to make sure that when you're operating a refinery you have process steam all the time.

And the state was able to take advantage of that type of operation that was primarily focused on delivering process steam to a critical and important business function in this state, and the byproduct in an odd way was electricity.

We've turned things in our head, and one of the things David was alluding to with respect to the treatment by the California ISO was, you have an almost perverted sense of what these plants are.

They are fundamentally steam plants, but from an ISO perspective you're a power plant. And they want to treat you like a power plant. But they are not power plants. And so many of the issues and frustrations and problems we have -- and I've just completed a seven year litigation with the ISO on the QFPGA -- are because of those fundamental differences.

You have engineers operating a system, which I understand and appreciate, but they have no capability, no understanding, of frankly the sophistication our existing utilities have in dealing with these types of industrial steam process operations.

Midset Cogeneration Company is a smaller project. It's an EOR field operation in the PG&E service territory. Again, state funds were not used to build this plant. About $25 million invested to do it. It came online in 1989. It generates 38 megawatts of electricity and about 24,000 pounds per hour of steam for the enhanced or recovery at the Midway Sunset field.

Surplus power is sold from that project to PG&E and serves about 28,000 homes. There was a long-term contract that was executed with the project when it came into operation. That's what sustained it, that's what got it through permitting. That's what allowed it to operate and continue its operation and continue to deliver.

That contract came to an end. And if you want to look at how regulatory uncertainty works in the state, but for the California Commission rushing in at the last instant in their procurement case and saying you know, for any of those contracts that are going to just terminate, and have come to an end -- and David was in a little bit of an odd situation because he wasn't an older contract or terminated, he was a new project that didn't become eligible for this, so he got left in true regulatory limbo -- but this project ended up looking at how do I get a contract?

What's my next field of operation? Well what, why does that matter, you're there, just continue to operate.

Well, it's very simple. If you looked at a utility power plant and said to them "we want you to operate on hourly payments for the next five years, but by the way we expect you to make your capital costs on maintenance and your capital costs on air emissions" they wouldn't do it in a heartbeat.

And neither can these projects. That's just an economic reality. So what happens with this project is it sits there and it continues to operate, even though they're well beyond their maintenance period, they're operating on a month-to-month basis on a contract that's available to them on an as-available basis, and if there's an outage there, and the ability of that plant to come back from that outage because there isn't funds set aside to do the major maintenance that's required, means it's probably lost to the state.

Now is that significant? You bet it is. Because it is only, it's the canary in the cage right now. That's the first one that you're kind of looking at as the typical situation if this state doesn't adjust or deal with its policies for these existing facilities.

The messages that we're getting from the state I think you've all identified. Pricing's unknown, secure contracts are not available, procurement as for baseload PURPA-related resources is nonexistent, the RFO's that are issued by the utilities at this point even are set up so that the QF's don't qualify.

They want fully dispatchable pricing or operation. Well, that's not who these plants are. They've never been and they will not be.

They want every unit to be a new construction. Well, is there something wrong with the megawatts from these facilities?

So, those are the types of projects that we're seeing. Our members are, nonetheless, even though they are not qualified for these RFO's are submitting bids anyway, and I think with the expectation of being turned down. And then what do we do next, where do we go?

There's a very old, African based saying about "stop talking, do." And I think as a lawyer who's practiced in this area for, unfortunately, 30 years, there's a part of me that's growing in my own frustration about the fact that we don't ever stop talking and rarely do.

It is time for this Commission and its sister Commission in San Francisco to do, with respect to these projects.

Do what? It's fairly straightforward. When this Commission looked at its Energy Action Plan and its IEPR before, in its draft resolution, it identified cogeneration explicitly as part of the loading order, high up on the loading order. Not quite high enough as we might like, but high up.

That needs to be put in concrete. That needs to be a starting point of something you do not next month, not after a year of more study, now. Because procurement's being based on that loading order.

What else must this Commission do in

collaboration with the other Commission? If we wish to preserve the very investment -- regulatory investment, policy investment, financial investment that has been made over the last several decades for thee types of units -- there needs to be an explicit reserve for capacity associated with this facility.

If you want this as part of your portfolio then you need to set aside an amount that says within that portfolio we're going to keep that amount of cogeneration, we want it, it's important.

I'm reminded of the words of John Fielder during the absolute depths of the energy crisis and units were shutting down and they weren't able to operate and they didn't know what they were going to do and they couldn't afford the net short.

In the paper he quite honestly quoted something I'm sure he regrets to this day that the biggest hedge we have against power deliveries in this state are the QF's, those contracts were long, firm, and, they continued to deliver, even in the face of financial and operational insecurity. That's why these units need to be looked at that way.

Do what? Stop talking, do something, issue an order, put this in the loading order, establish some form of reserve capacity for these types of units equal to the existing market penetration that you currently have, and assure that you also look at what do you do with the new units?

How do you take an obvious development that ought to be put into place, Valero, and let it sit there idle? It's silly, but those are the policies, that's the result of the policies that we have right now, which are really not policies, they're a default.

Thank you again for the opportunity to be here.

MR. LENSSEN: Thank you very much, Michael. I think we have a few minutes for some questions. If the Commissioner's would like to ask first?

COMMISSIONER GEESMAN: Yeah, let me briefly request, Michael, that you also file with us a set of recommended changes to the ISO tariff.

MR. ALCANTAR: We've got those ready to go, we'll be glad to do it.

COMMISSIONER GEESMAN: Good.

MR. LENSSEN: Any other questions from the Commissioners?

If anyone in the public would like to ask a question, please proceed to the podium and identify yourself.

MR. BRENT: Nick, can I make a comment?

MR. LENSSEN: Absolutely, Richard, while our others come up.

MR. BRENT: I was mindful that Commissioner Geesman understood that the word is cogeneration, and we talk about combining power.

When the United States Combined Heat and Power Association formed we specifically did not use the work cogeneration, as we were aiming at sizing around the thermal load of the customer as opposed to sizing it around the opportunity to sell electricity back into grid.

We found over the years of 1978 to really '82 when QF's were allowed up to today, it was an extremely difficult process. And I believe that Ralph exemplified why going beyond CHP into cogen and QF for these end users actually afforded CHP.

COMMISSIONER GEESMAN: Well, not to be

too much of a semanticist, I think when you went to combined heat and power as an industry you stepped over cooling load, and we missed it.

MR. BEACH: Thank you very much. My name is Tom Beach, I'm a consultant to the California Cogeneration Council. And one thing that I'd like the panel to address, probably Mr. Alcantar, is he spoke at some length about the threats to existing cogeneration projects in the state.

And we certainly agree with his comments there. And California put a lot of time and effort in the 1980's into developing a very robust cogeneration and CHP industry in the state, and that's a valuable resource that needs to be maintained and supported going forward.

But I think there's a flip side to making sure that existing cogen projects stick around for the future, and that is the potential that existing CHP projects can be expanded in the future, if they have the support of regulatory environment and assured places to sell their excess power.

And the written comments that the CCC has submitted to the Commission for this proceeding go through a number, have a number of case studies attached to them of existing CHP projects that have been or could be expanded in California if there is the right policy environment in the state.

And we even have some figures for, you know, 400 to 600 megawatts additional capacity that the state could have simply by upgrading from, for example LM5000 to LM6000 turbines, which have been done at a number of CHP facilities.

And I think that one of the big benefits of upgrading existing projects is that these are places that have cogenerated for 20 years, and in terms of the management focus and experience, it's there. They're in the business and they know how to run a CHP unit and they know what the regulations are, and they're willing to undertake additional investments provided that there's an environment for it.

So, if I could ask Michael to address that.

MR. ALCANTAR: Let me try with one example that's going on today at the California Public Utilities Commission, and it's really an anathema to even dealing with the short-term issues we're wrestling with.

If you were trying in the next year to sustain yourself, to maintain your operations as a QF and, as Mr. Beach suggested, even consider expansion or get to a place where you could rationally consider expansion, if you were in the SCE service territory today, the as-available price for capacity, established by the CPUC -- and this is a complete anomaly that occurred in 1994 and has never been updated -- is $4.93 a kilowatt year.

That's not $49, that's $4.93 a kilowatt year. In the other two regulated service territories in the state, SDG&E and PG&E, they have submitted through the same methodology that would apply to Edison a update to their as-available capacity pricing.

For PG&E that figure is $66.43 a kilowatt year, still not great but obviously better than $4, and for SDG&E $70.34. If the same methodology applied to the two utilities, and this was done today rather than, you know, several months from now, were it applied to Edison, their figures would be, round figure about $78 per kilowatt year.

And yet, the procurement case which opened the door for those who have terminated contracts to continue on, at least for a short period of time until the Commission can figure out what goes on next, made no change, or has made no adjustment as of yet, to the Edison figure.

That's just in the shortest of short terms. What Mr. Beach also tees up is, well what about somebody who's trying to make a commitment for the next five years, seven years, 10 years, 15 years, 20 years, 30 years?

The utilities are able to sign contracts, kind of with themselves, but nonetheless sign contracts with Resources for 30 years today. Those are not projects that seem to be made available to us.

The utilities couldn't even begin to conceive of taking their existing projects and operating at these prices. But that's what they expect of us. That's an un-level playing field by any estimation.

So, in order to get to the issues that Mr. Beach teed up, short term there needs to be immediate resolution so at least the numbers are remotely fair so people can operate, even on a short term basis for the next year, with some confidence that they can maintain their status.

But if you're making a five year capital investment decision you have to have -- and that's going to be absolutely status quo for anybody making a major maintenance turnaround, coming to the end of their contract, that would be the timing.

Or making investments for retrofits associated with air quality -- you've got to have a minimum five to seven to ten year contract commitments that you know what your revenue stream's going to be, to match up with what you know are your cost streams.

It's that straightforward. Are those being reached today? No. Are they being done? No. Are they set up to be done? Sure, but they've been set up to be done for the last year and a half. And I'm back to my theme, stop talking, do.

MR. LENSSEN: Great. I think we have time for another question. Please identify yourself.

MR. LOVELL: Yes, my name is Barry Lovell and I'm representing Berry Petroleum

Company. And this was less of a question, but just kind of a follow-on to Michael Alcantar.

Berry Petroleum is an independent oil producer that has been utilizing cogeneration in California since 1986. And I'd like to share just a brief experience in our efforts to expand our cogeneration.

Right now we generate approximately 90 megawatts. Roughly ten of that is used internally, the rest must be exported to the grid. And that only supplies about half of our enhanced oil recovery thermal needs.

So, in the heart of the energy crisis we prepared permits to construct two new cogeneration facilities, roughly of 90 megawatts. We were willing to invest our own capital in that.

And after approximately a seven month effort of finding that there was just absolutely no way we could find a home for that power we gave up that effort and actually installed additional boilers to generate that enhanced oil recovery.

So here's a case where we have a private company that's willing to invest its own funds, and again, there's an obstacle out there to having a place to put power if you're a large facility that needs to export to the grid.

The other thing I'd like to share is, we have three contracts, as Michael has mentioned, which have already terminated. And we've gone through the experience of what happens when you have an existing cogeneration facility and your contracts terminate.

The first experience was that we approached our utility -- now this is a plant that had been operating for 12 years, operates 24/7 -- we were going to make absolutely no operational changes. And it took us a year to get an interconnection agreement with the utility to operate exactly the same as we had been operating.

The only difference was someone else was going to write us a check for that power. That clearly to me is a huge obstacle.

The other thing we encountered is we had to go through the participating generator process at the California ISO. And what you end up signing is a very simple 13 page document that basically says you're going to comply with every ISO tariff that will ever be written.

And many of these are confidential and you can't even see them. So for someone who's not in the power generation business this is kind of a scary process.

We went through that. We installed all the requisite ISO metering. And now what we have recently encountered is, because of our status as a qualifying facility that sells electricity to a utility and we are a participating generator, we are going to get hit potentially with a penalty by the ISO that no other qualifying facility has that has not signed a participating generator agreement.

Again, this is one of those obstacles that you encounter. And the other thing -- and Michael focused on this very well -- we are operating under one of these interim agreements. And for the first two years after our contract terminated the utilities refused to sign contracts with us despite the fact that there is a federal law, PURPA, that required them to do so.

And only by the actions of the Public Utilities Commission were we allowed then to sign a short-term agreement with the utilities. And it is not something that you can economically operate under for an extended period of time, so, you know, I just need to stress, as Michael Alcantar has done, we really need to do something to not only allow new cogeneration facilities to come online, but also we have to do something to keep the existing facilities online.

And it's a huge uphill battle. ?The obstacles that we see from the utilities are huge in this regard. Thank you.

MR. LENSSEN: Thank you very much.

MR. ALCANTAR: May I just jump in on a couple of points, quickly?

MR. LENSSEN: Quickly, sure.

MR. ALCANTAR: First -- and I appreciate the comments by Berry Petroleum -- the contract that they were able to sign short-term was also just recently the subject of a utility writ at Court of Appeals challenging the legal authority of the California Public Utilities Commission to even order these contracts.

So we're hopeful that's going to be successfully prosecuted, but that's the market we're in. Those are the things we're looking at. And I couldn't help but double underscore what the state looks at if it starts to think that these cogeneration units go away, you'd want boilers installed.

And then what's the ramification of that? The boiler gas that you now need to deliver to one plant. You have a return of load that used to be served by outside generation being shoved back upstream. Who's going to provide that? Where's it going to come from?

The benefits from these units, when you calculate them you can see them, they're so patently obvious. And yet we are engaging in a public policy that says let's encourage you all to go build boilers.

And I don't think it's this Commission, and I don't think it's the CPUC either. This is a fight about market share, this is whether or not we're going to have this type of industry in the state when the utilities really don't want it, period.

MR. LENSSEN: Next question?

MR. EVANS: Hi, I'm Peter Evans with New Car Technologies. Those of you that are familiar with my work know that I'm particularly interested in smaller projects, even distribution, connected projects.

And so, I think Nick's comments that, you know, when we talk about very low payback rates required by customers, really that's the customer saying look, we don't want to invest our money in this.

Each of our panelists said that this isn't our core business. Both of those are bigger problems as you get to smaller customers.

And so my question is, when you look at the objective of increasing penetration and the unmet potential, my question for the panel is, and there's two.

One is, how important, to achieve that objective, are third party project integrators who can come in and basically do the project turnkey and finance it; and then the second one is would it help or hurt if the utilities stepped into that role, particularly for smaller projects?

MR. ALCANTAR: I have a historical perspective. Twenty-five years ago Priscilla Grew, who probably very few people in this room know, who was a Commissioner at the time and a little bit of an odd person, and she was an appointee of Governor Brown and a very active and strident supporter of cogeneration.

She did outreaches to, at that time, Getty Oil Company and Chevron and other oil industries to build these projects. Because they had the same, the things that you're talking about on board are not new, they've been around for a long time.

If you're an oil company you're not an electricity producer, it's not your core business. And it's the same problem, the same problem whether you're very small or very large. And it does require a champion inside to carry those things forward and prove out the benefits.

Those ar proven out, at that point in time, because there were many, many promises about assuring a stable marketplace, stable regulatory policies, and even putting them in contract to make those stabilities real tangible.

I don't know whether third party suppliers in that marketplace were really helped, but it would be my experience that the utilities providing that service would defeat a good deal of the incentives that the businesses might really have about getting there.

MR. LENSSEN: That's interesting, do you have something to tag on to that?

MR. YATES: That's an interesting notion. I would just underscore, from a food processors perspective, you're putting your steam supply in the hands of another. And without steam you're dead.

And when you are in a seasonal business even a few hours counts for a lot of food. So, I guess I'm saying there's some reluctance there, without some assurance or some backup from the third party provider, or maintaining your own ability to instantly produce steam with some sort of a standby load following.

But if you take a large tomato processor, you lose steam for a second and you've lost 24 hours of production, because it's an aseptic system and you've got to clean 20,000 pounds of food out of it and start it up all over again. So, they're pretty protective of that.

MR. LENSSEN: Tomatoes and semiconductors have a lot in common I guess.

MR. RENNE: Just, to address Peter's question. I think the set of exchange of risk, whether it's third party provider or at the end user deploying their own capital, it still presents a problem.

If third party has to make a profit at this, then sort of all the economic motivation will then result in the third party and the end user would specifically be interested in some other component of it -- increased infrastructure or reliability or some other benefit -- but it certainly wouldn't be economic.

There isn't that much margin to do these projects where I think a third party is going to have a profitable business without incurring some dramatic risk or have some tremendous procurement for fuel resources that are done better than I guess industry average.

So I don't really see that fueling the market. Where I see the opportunity being greater is overcoming paradigms of applicable distributive generation. And I think a lot of times we look at whole sites where we should be looking at the most logical application.

Silicon Valley does a process ,silicon now, but it's ubiquitous, almost every building in the valley has a data center ranging from 50 to 100 KW, depending on the size of the building. These are 24/7 loads, nonstop, uninterruptible.

There's emerging technology in Capstone, you know, Kawasaki makes a 20 ton absorption unit. So you could start pairing up small micro turbines with absorption and sort of fulfill that one component that's ubiquitous in our entire society now, and that's data center application, where you do have a reliability component.

So there's where I see third parties potentially being able to market to end users with an economic situation that could be a lot more compelling than trying to do a full site. It's just really a specific application that already exists. There's where I think third party could potentially have some impact on the market.

MR. BRENT: Let me, um, I'm going to sound like a contrarian here. To the two points, third party providers and utilities stepping in. I think there's a number of good models for third party providers.

I'm reminded of the energy service companies and their stake in the federal energy management sector. They have done fairly well under some pretty tough constraints of capital and a host of engineers who inspect the level of contract and technical compliance with a fine tooth comb.

And yet they've been successful and continue to be a robust model for over 500,000 federal facilities not only here in the US but around the world.

They can do things that we can't do, but that doesn't mean we're going to let them alone, because we are engineers and we inspect the detail. Ralph would be abdicating his responsibility if he didn't oversee a third party provider.

In terms of utilities stepping in. Again, sort of a different view. I'm a manufacturer of the hardware. One way or another we're going to sell this hardware. We're either going to sell it to the utilities or we're going to sell it to a third party provider or we're going to sell it to the end user, but we want to sell hardware.

We think that if we're talking about customer value, no, probably not. Unfortunately the utilities, some of the large ones, have not demonstrated the word customer, they've demonstrated the word ratepayer.

But I also think that they know best where the grid is constrained, they know best where the air quality is at risk, and they know best, if they're doing their integrated resource planning properly and their distribution planning properly, they know where it's going to be constrained.

Take southern California. Everbody's moving to the east -- Riverside, San Bernardino, Palm Springs. It's hotter out there, we're going to be getting more air conditioning load. I hope someone in SoCal Edison is taking that into consideration when they're planning their distribution.

They may have a very appropriate role in partnering the integration of combined heat and power, and I would talk more to the new stuff, then we might suspect. But, they'd have to mind their P's and Q's, because their history is abominable.

MR. LENSSEN: Thank you for the comment to the panelists. If I could just quickly add on that.

Our research has found that energy users are fairly well split in terms of their preferences of owning and operating or leasing or even outsourcing their distributive generation or CHP project.

So it definitely is something that --

there is a need for it, but the track so far in a lot of the outsourcing companies has been rocky at best.

Secondly, on the utility issue, we're starting to get, just in the California policy statement from five years ago where we're considering or promoting utility involvement in DG is revolutionary from where we were, but we're also seeing action in some other states.

Hawaii, which is currently under, you know, the utility there wants to build and develop CHP that's utility-owned. And I think it's important to keep an eye on Pennsylvania where an alternative energy standard which was approved by the state last December specifically includes CHP as a means to comply with the Tier two requirements.

It's analogous to the renewable portfolio standard here in California, but it's much more expansive than just renewable energy.

We have time for one last question, a short one, thank you very much.

MR. O'CONNOR: My name is Tod O'Connor, I'm building on the point you just made. I'm here on behalf of the Department of Energy and the combined heat and power initiative.

And one of the policies they're looking at right now is looking at waste heat recovery as renewable, treating waste heat recovery as renewable.

The state of Pennsylvania is doing it right now, the state of Nevada has done it, several years ago. And with the state of California looking to accelerate the percentage of new power that utilities would need to buy from 20 percent to 30 percent by 2017, and by moving the 20 percent limit to 2010 the state needs to be aggressive in looking at all viable options for meeting those standards.

Qualifying heat recovery can be part of the win/win people are talking about today in terms of why would the utility take the power. but now you can engage in that kind of discussion, there are long-term contracts that are available to buy in baseload renewable that may not be available to standard QS.

And there's also the REC issue. Now you have a quantifiable economic benefit to qualified heat recovery that didn't exist before.

So I think that's a new territory that

needs to be looked at. I look forward to providing comments on that as well, but you raised the issue, I'm glad you did, I hope it goes into the record, and I would like to see it go in the report to the Legislature. Thank you.

COMMISSIONER BOYD: I for one am glad you made that point, because I've been introduced to that in the last six months or so, and that's an extremely fascinating area and subject. And there was a gentleman from the east coast, an extreme proponent of this subject, that's had a lot of experience.

I wanted him to be here today, but he just couldn't make it. I think this is a field ripe for additional inspiration.

MR. LENSSEN: All right. I think our time is more than up. If I could ask Mark Rawson to come up and tell us how long the break will be, and when we can reconvene.

MR. RAWSON: We can reconvene in five minutes -- I think we're just going to continue. Is that okay, Commissioners?

We'll continue with the next presentation, and then look at doing a lunch break after that.

Thank you, panelists, for taking the time to share your thoughts with us. Before In introduce the next speaker, just one housekeeping item that we missed this morning.

We are seeking public comment on today's discussion as well as the technical reports that we posted as a part of this workshop. If you'd look at the workshop notice that's online it has the specifics of how you can submit written comments to this proceeding for the IEPR.

We're going to shift gears a little bit here, and take a look out into the future of what potentially could happen in California if the state were to pursue an aggressive promotion of CHP.

We're fortunate to have a person here to speak with us from Denmark, a gentleman by the name of Paul-Frederik Bach, who works for the Danish transmission system operator Eltra.

They have been somewhat of a living laboratory on what can happen when you have high penetrations of CHP into a power system, and this discussion is going to talk about what some of those challenges are, so that as we go forward in our policy considerations we have our eyes wide open about what kinds of things we need to look towards in the future in terms of how the system needs to adjust to a more distributed nature, and what kind of challenges that creates for other important parts of our energy delivery system.

So with that, let's have Mr. Bach come up and make a presentation on Denmark's experiences.

MR. BACH: Thank you, Mark. Commissioners, ladies and gentlemen, it's an honor for me to have this opportunity to present the events from introducing distributive generating in Denmark.

This first slide slows Denmark is just a tiny part of Europe, and for historical reasons there are two electrical systems in Denmark, the western and the eastern. And from the western system we are synchronously connected to Germany, that's the reason why we are operating separately from the eastern system.

But we are part of the nordic power market north pool, and I'm going to tell you the story about how our power system was transformed from a very traditional, centralized generation system in the mid-80's into a distributive generation system by the year 2000.

My issues will be a little bit about political background and the history about penetration. The biggest part of my presentation will be concentrated around what I call risk and rescue, and also about the short-term measures we are preparing in order to solve the present problems.

And there will be just a little bit about the development of a new system architecture and what we are looking for in the future. But in my office I am using most of my time looking into the future.

I thought it might interest you to know a little bi about the political background. Houses in Denmark must be heated most parts of the year, and we have a very long tradition for CHP. All native urban areas have had additional heating systems since World War II, or since the 50's at least.

And then a lot of new initiatives came after the energy crisis in 1973. I'm not the right person to give the details, but I have added some references which you can find at the end of your handout.

But the result has been that a lot of

small projects have been added to the large ones. They have not all been profitable, that was one of our theories, that if you are going too small you also have an additional cost for that.

But at the end, the district heating has a 60 percent share of all rooms, space heating, and 74 percent of that is CHP, which means that CHP is covering about 45 percent of all space heating in Denmark.

The Danish Environmental Protection Agency, just a couple weeks ago, published a new report because the present right wing government would like to see if the benefits from the energy policy could justify the cost.

And you may know that the carbon dioxide issue and the Kyoto Agreement plays a role in Denmark. And some reductions have been achieved, but there is also a way to go in order to meet the Kyoto targets by 2008.

The contributions by industry shows that the energy business has provided the main contribution of all, but it also reveals the problem of electricity export, because the Kyoto Agreement does not reward the results of exporting electricity.

And looking at some selected initiatives, this shows that wind power and CHP are getting the biggest contributions, and the cheapest ones. If you look at the other end you have things like improvements of buildings and subsidies for solar and heat pumps and biomass are getting rather small contributions and they are also rather expensive. But this is quite a new report.

Turning to what really happened. We had this search of small scale CHP in the mid-90's. And the wind power came a little bit later. And it really was unexpected, because we had a national target saying that by 2005, which is now, we were supposed to have 1,500 megawatts for the entire country, but we have now more than twice that amount of wind energy.

So we were not quite well prepared for that amount of distributive generation. The result has been that more than 50 percent of the installed capacity is what I call distributed generation, and even more than 50 percent of the electricity consumption is covered by distributive generation.

I didn't, if I had heard this round

table discussion when I made the presentation I might have made a different presentation, but I can add here that of the CHP, the 32 percent of energy from local CHP, about 20 percent of that is from industrial projects.

Both wind power and local CHP are what we call prioritized. This means that they can produce the energy that they want and they are guaranteed a price for that energy. The transmission system operator must buy all that energy and pass it on to end consumers.

This has probably been necessary in order to obtain the penetration which we have seen. But these are the stiff roads which are causing concerns, as I shall show you a little later now, and which we would like to change.

I have a case I have taken from January 2003. This is just the electricity demand as it looks over an entire month. And you see that we have a baseload share of about 1,800 megawatts.

Now I have subtracted the actual wind power, and suddenly you see there is no baseload market left. And then what actually happened, because for different reasons the thermal unit marks also have a share reduction.

We have an export which we cannot avoid, we must export whether somebody wants to buy it or not. The reason for that is that the operation of central units is constrained by heat demand or reserve duties, and so what happens is we had this export of electricity regardless of the electricity demand in neighboring countries.

So the result of all this is the market for traditional baseload units has been distorted by the wind power, and it is doubtful if producers of that will invest in new baseload units. And it's also doubtful if they should.

The overflow of electricity during windy periods means that wind power and CHP electricity are competing for limited electricity demand. And the priority is causing unintended export of electricity, and as I said we have no credit on the Kyoto account for that export.

So what should have happened is that the wind power should displace thermal electricity, because we are using fossil fuels and natural gas for electricity which nobody needs.

Now I'm going to the part of my presentation which I'm calling risk and rescue. And a little bit about the company Eltra, which has the main task to maintain security of supply, electricity.

But we have been taken over by the Danish state on the first of January this year, and we are being merged into a national company which will be the future national TSO for both electricity and gas.

In this system supply and demand of electricity must be equal, but electricity consumers decide demand profile. Wind power is controlled by wind only. Local CHP so far is controlled by heat demand and time of day tariffs. And the last generators follow market signals that are constrained by heat demand and by their design as baseload units.

So we have a system where the so-called load following capability of the domestic production is inadequate.

This workshop is not so much about wind power, but wind power plays a large role in our system, and particularly, one thing is the wind power is fluctuating so much, but another thing is that the predictability of wind power is poor.

And if we have a forecast deviation of just one meter per second this means 320 meter watts on our total production. We all work when the weather people are talking about a fresh breeze, that's what they promise us.

This means anything between 200 and 1,600 megawatts. This is a good program.

So, these arrows and the full load following capability cause a high need for so-called regulating power, which is also an item which the TSO must purchase. We purchase it locally and we purchase it abroad.

And this means that maintaining balance in the system between production and consumption has become very expensive and also rather difficult.

Reactive power, this is a technical issue. I shall not explain that in detail. But we have too much reactive power transferred between the local grid and the transmission system.

The reasons for that is that the local CHP units are not following the need of the grid, just some pre-scheduled plan. And the wind power has not been sufficiently compensated.

And this is an example, that we have resources locally but we are not utilizing them properly, and what comes out of this is now we are discussing money, because producing reactive power has a very little cost for the producers but a very big value for the system, and of course the owners of these units know all about that and they want the money.

Now I'm going to look at the impact of the market, and that's nearly the same story. We have a lot of production from wind and local CHP which do not produce according to the need of the market, but according to their own needs.

And this means that we have an area price in the nordic market, and our price is typically somewhere between the north pool system price and the German EX price.

And, on the next slide, again I have taken January 2003 as the case. As you can see, the second week of that month we have practically no wind power, and then follows days with a very high share of wind power.

And what happens with the price, at that time there was a shortage of energy in the nordic market so the nordic price was quite high and the continental price was more moderate.

But the price on our tiny system was

going up and down between, it is very high when there's no wind power, and it is more to the german prices when there's a lot of wind power. Or sometimes even zero, very, very difficult, below the German prices when we have the surplus.

The problem with that is the market players have limited confidence in a volatile market and they will be reluctant with participating in that market.

This is also technical slide. It is in order to show where in our system we have the production. We have a little less than 50 percent of the production in the transmission system, which is within the range of our controls, that's what we can see from our control room and that's what we can control.

And then we have a little bit more than 50 percent which cannot be dispatched and is completely beyond the central control.

This causes some security problems, and maybe this is a little bit technical, but in the local grids we cannot maintain what's called normal N-1 security. We have some local grids where generation exceeds the local load, and these local grids must be extended according to special rules.

And it's difficult for us to make security analysis on our systems. And then, when we have some faults, we have experience a lot of reductions, for instance after lightnings. Not because the local grids have no fall through capability, but because of the protection system.

And then we have problems with the so-called low hitting systems, because the load and local generation have not been separated. We are showing this, illustrating this problem by giving this picture of the transmission system and the transfer point to the local grid.

And in the traditional system with oil production at the upper level, at the transmission level, it's easy to predict what's happened in the local grids because they are quite uniform. You just have to observe the transfer notes and then we ned data for the entire transmission system.

But now the local grids are very unpredictable. We call them active grids but we do not have the data necessary from these grids.

So far our security has been acceptable. The reason is the nordic buck market, the real time market, the strong interconnections to Norway through Germany and particularly that we have a strong AC interconnection with Germany. Some would claim that we just export the problems.

We must say that if we did not have the access to purchase circulating power in neighboring countries then we frequently would have curtailments of wind power and maybe other disturbances. So this is very important when we are talking about the way we have solved the problem so far.

So, as summary, maintaining the balance of active and reactive power has become difficult and expensive as a lack of confidence in the electricity market among market players and the system security is not as good as it should be.

Therefore, I have to add that distributive generation is not the problem. The problem is that it came too fast, and that we need to redesign our system architecture for that purpose, and it takes some time.

And we have resources also in local CHP units we could contribute to system balance and security if they were just operated the proper way, but we started with giving them this priority so they can operate according to their own needs and not according to the need of the market or the system. And that's what we are struggling with today.

So, what are we doing? This is a merit order curve for what we should do when loads are going down or when we have this surplus of energy.

The first thing we should do is stop gas-fired local CHP. And this is first on the list, whether we include externalities or not.

This was quite surprising, this is a report made by Danish Energy Agency back in 2001. Nobody knew how expensive it is to operate a small gas-fired unit. The maintenance is quite expensive, and when using natural gas it also has carbon dioxide emissions, which is considerable.

Next on the list comes the use of electric boilers for heating water for district heating purposes.

And then comes stop of coal fire units. Everybody would have expected that to be first on the list.

And then at the end the stop of wind power.

Everybody's talking about now that new wind generation units will be controllable, so we could stop them, but this curve shows that this is a long sequence. So we should prepare ourselves to organize the system so that we can stop according to this list.

Local CHP units have three modes of generation. They can produce heat only, they can produce electricity only, and they can produce combined heat and power, or cogeneration.

So far legislation prevented use of this flexibility in Denmark, but following the report I just mentioned, a new act allowing market operation has been valid as from the beginning of this year.

I should add that this problem is not there for industrial CHP units, and we have a good cooperation with industrial owners of CHP units in order to develop new ways of operation.

We have a pilot project paving the way for transition, going from prioritized operation of local CHP to a market based operation. And I could have given more information about that project. It addresses some of the problems discussed at the round table.

The pilot project includes 30 units with a total capacity of 400 megawatt, sized between 3 megawatts and 100 megawatts. And 6 balance responsible operators, because the owners of the 30 units do not have energy as their main business.

But the balance responsible operators are those operating on behalf of the owners of the units, and we sense this is the way ahead. And the CHP schemes could contribute further by electric water metering, meaning that they get the necessary steam or hot water or whatever they need from electrical processes if there is a surplus of electricity in the market.

Other short-term measures would be to introduce price responsive electricity demand to encourage or to force local grid companies actually to control their own grids, both regarding reactive power and voltages and emergency situations.

And then the forecasting of wind power must be improved. We are currently using weather forecasts from more than one met office. We are getting forecasts as far away as New Zealand, and we are developing our own forecasting tool using the so-called ensemble method on a cluster of computers housed at Eltra.

Moving forward, what sort of system architecture we need for controlling the system with distributive generation. It is important that we have sufficient domestic resources for maintaining balance between demand and generation.

It is important to improve operator knowledge of what is actually going on in the system, both locally and centrally. We need efficient system control, particularly during emergencies.

We need effective defensive measures against blackouts, and we need black start capabilities using local generators.

Our neighboring countries, particularly in Germany, are preparing very ambitious wind power programs. Germany has just published a study on integration of 36,000 megawatts of wind generation by 2015, which will cover about 16 percent of the electricity consumption in Germany.

That's a reason why, as far as Denmark is concerned, we must develop domestic research and other ancillary services in order to contribute on equal terms to stability and security in the interconnected European power system.

And we had very much inspiration from this country, from EPRI's so-called Intelligrid project and from DOE's Gridwise project. They have a very important point that we need to develop communication systems covering the entire system.

So far, in Europe at least, TSO has had access to data on its own grid, but knowing very little about what's going on in the neighboring grid, and also without data of the local grids.

In order to be able to make better forecasts and particularly better analysis, we should be able to look into the neighboring system and to have data for all the local systems within our own area.

And then, to my final slide, the question is if we are in a race and we had to improve the system, we had to make a new system architecture to operate properly with the distributive generation, but if we are getting even more wind power are we then going to lose that race?

I'm analyzing it from this model. We say we have an electricity market with a certain electricity demand, and then we inject wind energy, it's always competitive, and then there is a residual market which we are analyzing.

And some people have suggested, the wind energy among others, that we should go as far to 35 percent or even higher of the electricity demand.

One thing is certain. If this will be made, we have to reduce electricity production from external sources, even from CHP steams. And we must be able to operate the system completely without thermal units, which our operating people are very concerned about.

But the commercial market players will find good opportunities within the residual markets, no doubt about that. But they are not going to build new baseload units, they will have to replace those by a more flexible type of unit.

And it uses an international trend, what we expect it is, it's important that the interconnections between countries are reinforced and that the electricity markets are better connected.

In this case because it will be very expensive to serve the residual market the electricity consumers will also have to face an increased cost of electricity, and this is the type of difficult point to discuss, but it's beyond any doubt that if you cannot use traditional baseload units with a low cost per energy unit you will get taken for an increase from the consumers point of view.

MR. RAWSON: I'm going to keep you up here for a second, I'm going to keep you on the spot for a minute in case there were any questions. Were there any questions from the dais?

COMMISSIONER GEESMAN: Yeah, I have a couple. If I understood you correctly, Denmark has only gone to a single, national integrated grid this year?

MR. BACH: Yes.

COMMISSIONER GEESMAN: And when you mentioned local grids, how many local grids are there in Denmark?

MR. BACH: There's a difference between the eastern part and the western part. As far as the western part of Denmark is concerned, we have between 40 and 50 local grids. There is a much smaller number, again for historical reasons, in the eastern part of Denmark.

But this means that cooperation with the local grids is a very important task for the system operator.

COMMISSIONER GEESMAN: And you're following now the EPRI Intelligrid, or the DOE studies, I think they call it Wisegrid, to better integrate your system?

MR. BACH: Yes, sometimes we say we have the problem, you have the solution. But we think that we've found very good ideas, particularly concerning the need for new communication infrastructures in the Intelligrid. It's the one I personally look most upon.

COMMISSIONER GEESMAN: Thanks very much, and thank you for being here.

MR. ALCANTAR: Michael Alcantar. Sir, what was the pricing incentive that is provided to wind producers that brought your, for lack of a better word, gold rush of wind developers in Denmark?

MR BACH: Development of wind power started with units in the magnitude of 50 kilowatt or so, and they were quite expensive. And they needed other incentives for their development.

Then, as the unit sizes grew, they were

making more money and it was becoming by far the best investment you could make in Denmark. And then they had to change the system, back in the year 2000, so they had a more realistic level of incentives.

But as always in Denmark, you make a transition period. And the year 2000 was such a transition period, so everybody wanted to get a project at the old price, and that's why we got that surge particularly in the year 2000.

MR. ALCANTAR: Now had you been able to plan and control that surge of wind power production, given you have an 1,800 megawatt capacity market, you would have been able to balance and control your CHP and your wind producers to integrate a bit better, had you been able to do that, wouldn't you?

In retrospect, it's easy to look backwards of course.

MR BACH: Hopefully, but I'm not sure that we saw at that time the need for a new system architecture. What we are saying today, what we are trying to tell the politicians today is that the increase in distributive generation should not go faster than the system architecture is prepared for. But that might be wishful thinking.

MR. ALCANTAR: Yeah, I'd agree with that last comment. But had you planned, perhaps, and you had a need assessment as this state does for new generating units coming online for example, that might have changed rather dramatically the situation you're in today, correct?

MR BACH: Yes, that's correct.

MR. DYCK: That's a very fascinating model you have there in Denmark. A question for you, it seems as if you either have a differential advantage in terms of wind resources compared to your neighboring systems that are connected to you.

I assume that they have to use some carbon resources in order to follow your load, and I would imagine then there must be some trading of environmental credits under Kyoto that takes place between you and your neighboring grids. Is that true?

MR BACH: No, there's no credits between us and our neighboring grid from --

MR. DYCK: In terms of environmental credits?

MR BACH: No. So we are, as far as the

Kyoto obligation is concerned, we are alone and we must balance our own system.

MR. DYCK: But you continue to lean on the neighboring grids for regulating power?

MR BACH: We did so far, but there are several reasons that we should not expect to do so in the future. One is the expansion of wind power in neighboring countries. Even in Norway they are planning to go ahead with wind power.

And another reason is that neighboring countries are being more concerned about the cost of that service. Market people say it doesn't matter if you buy things in your own country or neighboring countries.

But we feel we should have the resources available in our own country, then at a given time the market can decide whether to purchase resources abroad or at home.

MR. DYCK: Okay, well, I guess I'm a little bit surprised that there isn't more trading that goes on there, on the environmental side. Because, in effect, they must be using load following gas turbines to meet some of your instances where wind is not blowing.

And then there are basically, you're

exporting the CO2 obligation to them?

MR BACH: I would wish that we could export our CO2 obligations, but -- you see, there is one other reason. The reference here is 1990, and this is actually the last year where we had a net import for electricity for a year. So it started a bad year, and it's very tough for Denmark as a nation to meet the Kyoto target because the reference year was an import year.

But we are alone in that respect, and the other countries are not supporting that.

MR. DYCK: Well, thank you for being here.

MR BACH: Thank you.

MS. PETRILL: Hi. I'm Ellen Petrill from EPRI, so thank you for you comments about the EPRI Intelligrid. And thank you for being here also and sharing your story. This seems like a situation of be careful what you ask for.

And it sounds like there was a lot of interest and listening to renewable energy of course, and consumer control combined heating and power, and policy makers sounded like, I'm guessing, they made a lot of decisions without maybe thinking through the physics of the situation.

And you made some comments about how to fix the problem now, but do you have any comments on how it might not have happened from the beginning. So, maybe more analysis, or discussions among different parties, before it started off down the road?

MR BACH: It is quite a tough question, because I'm not sure we were so clever by then. Also, as you see, the Intelligrid has come with some inspiration at the very late time and hour of development. We didn't know these points by then.

But I think a more slowly development of the distributive generation could have given us better opportunities to maintain control throughout the time. So, I wouldn't say that we knew at the start of this development what should have been done, but in case we had a more slow development it would have been easier for us to handle the situation.

MS. PETRILL: Thank you.

MR. BEACH: Tom Beach with the California Cogeneration Council. Thank you for your remarks. I was very interested that a lot of the CHP in Denmark has the flexibility to operate either as electricity only or heat only or in a CHP mode.

Is that mainly the district heating systems, or is it the industrial CHP as well? And sort of a follow-up question, has Denmark done anything to encourage CHP operators to install the flexibility to be able to operate in those three modes?

Here in California we have a lot of CHP but most of it needs to both make steam and produce electricity at the same time, and it does not have that flexibility.

MR BACH: That was a very good question, because we are, there's a difference between the CHP owners operating a district heating system and the industrial owners. And those operating district heating systems are typically financially weak and do not want to take any risk whatsoever, while some of the industrial operators have more, what should I say, they have a spirit of trying new ideas, and they also are willing to take some risk.

And particularly, in our country this is the greenhouse owners. And the best of them are making more money on electricity than on flowers or tomatoes or whatever that could be. So this is very inspiring, very interesting.

But there are also political barriers to that, because the CHP system was helped through by incentives, and they should not be disturbed by anything. They had their priorities. So I would say that it has been a long process to convince political system, all the interest groups, that this is a resource that could be utilized if we are doing it the proper way, and nobody needs to lose money.

And this new legislation has been made in a way, our idea was that when the local CHP units are going through the market the system should be that they are having the same money if they are doing it properly. Then they could lose money or win money.

But the political theme was that they could never lose money, they could only lose money. But that's politics. That's how it ended, they can do whatever they like as a dip in the past, and then they would not lose money. A?nd then, if they are clever in the market they can have a lot of profit. And okay, that's going to work too.

MR. RAWSON: Any more questions from the public?

I wanted to ask, you mentioned in some of your comments about looking forward, about looking at distributive generation trying to provide other types of services,, you mentioned reactive power, you mentioned black start.

Have you actually started modifying their ability to participate in those ancillary services markets currently in Denmark, or is there a timeline for beginning to participate in those markets?

MR BACH: We are doing that as pilot projects, and again we are using the strategy that we select the most progressive owners and then we develop new facilities that way around, and the black start capability is very interesting, because we have several other units that could contribute to a black start capability.

And there was, even in Denmark there was a blackout,not on our part, but in the eastern part of Denmark and Sweden there was a blackout in 2003, just months after the blackout in this country.

And just in one place, in an island

called Bernholm in the Baltic Sea, there was a local unit making a black start. But all the others did not try because they just sit down and wait until electricity comes back from the transmission system.

But actually we have a big resource that, if it was organized for it it could be used for a black start, and we could reduce the time we need for building up the system after a blackout considerably if we mobilized that source.

So personally I'm a little bit occupied by that possibility, but of course I hope we avoid the blackout. But my experience is also that the people around, the owners of that sort of schemes, they are very eager to contribute if there is an emergency. If they could they would.

So it's rule is red tape from preventing us from utilizing all the resources we have in the local systems.

MR. RAWSON: And that's the Puddel project you mentioned in your talks. What's the timeline for some results out of that pilot program?

MR BACH: The Puddel project is running now. We started the preparations last year, but it's running, the pilot period right now. But the purpose of the Puddel project was to mobilize regulating power so the local CHP are not only contributing to the day ahead market but to the realtime market.

Which is what we need because of the bad forecast of wind power. And again, we have found in this project there is a very great interest among the participants to contribute, so I'm quite optimistic that this should succeed.

The barriers are more of a political type, or some just traditional thinking.

MR. RAWSON: Thank you very much, Mr. Bach, for coming to us and talking about your experiences. We greatly appreciate it.

(applause)

Commissioners, I'd like to recommend we break now for lunch, and pick up about 1:00 with the next part of the discussion. Thank you.

(break for lunch)

MR. RAWSON: We spent the morning talking a little bit about the end users perspective with the panel discussion we had, and then shifted gears a little and looked out in the future to some of the issues we may want to consider as we start to look at some of the policy options the state should consider with respect to CHP and distributed generation.

This afternoon we're going to focus on sort of the meat and potatoes of the market assessment and policy analysis that was done by the team put together by EPRI. The end user research was presented by Nick Lenssen.

The next two presentations, I'm going to introduce them both right now, and we will have Q& A in-between, but they kind of both go together. Ken Darrow, who is a Senior Project Manager with Energy and Environmental Analysis, Incorporated is one of the EPRI team members that worked on this assessment.

And he's going to present the base case analysis of what the situation is today with respect to CHP in California, given the current policies that are in place, and where that will get us by the year 2020.

We'll follow that with a public Q&A, and then we'll shift gears and talk about the policy scenario analysis after that.

So with that, Ken?

MR. DARROW: Thank you, Mark. And

again, as far as input for the study, we really want to thank the Commission staff, Mark Rawson and Scott Tomashevsky in particular, but also Linda Kelly and Jairam Gopal and Ruben Tavares, that provided us with some of the input assumptions or help on generating input assumptions that we needed for the project.

As Mark mentioned, we're the second of the three segments of the study, the market analysis piece in yellow there, and we're going to be talking about the technical and economic market potential, market penetration, and a scenario analysis. And providing the results of that part of the work, on the scale of the CHP opportunity, and what some of the key market segments are.

We first characterized CHP in California today, and there's over 9,000 megawatts. I got a little bit excited in preparing this slide and said that that was the highest capacity in the US. Actually Texas has more because of all the petrochemical industry, but California is second.

And within California, within this 9,000 megawatts of existing capacity, the enhanced oil recovery market is the largest single share of that, with all of the steam requirements for the enhanced recovery process.

Of the remaining part, it's really concentrated in five process industries, from food processing refineries, metals, paper industry, and chemicals. And then other industrial application, seven percent of the total.

The slice of the commercial and institutional market for existing CHP is only 18 percent, so of this total it represents just under 800 sites, and more important I think, most of this is pretty big stuff.

Only 17 percent of this existing stuff is under 5 megawatts, and in fact over half the capacity is in systems that are over 50 megawatts.

Now, what goes in to the competitive decision for implementing CHP. That was part of our modeling problem, that was our modeling issue. And I'd like to digress a little bit to a project we did a couple of years ago for the Federal Energy Management Program.

And we did specific CHP feasibility studies for four California facilities: an Air Force base in southern California, a military college in the Bay Area, a post office.

But, anyway, when you do a detailed

facility of whether a facility should adopt CHP we had to collect the 15 minute electric load data to get a picture around the clock of what that electric facility use is.

We had to characterize the thermal loads at that facility, collect the billing data for their electricity and natural gas, go through the thermal equipment that they had, and also look at those loads and size an appropriate cost-effective CHP system.

And then went out to vendors for quotes on equipment costs and performance, do an economic analysis, and come up with some figure of merit, like payback.

At that point then, the customer has to react to that depending on what their cost of capital, what their availability of capital, what their other constraints are. But anyway, that was the problem for analyzing one facility.

And our job was to look at all of the commercial and institutional and industrial facilities in the state. So, to do that we couldn't go into that same degree of detail that an individual feasibility study would entail.

So this is a graphic representation of

the overall pieces of our approach. In the upper corner here, on the applications, we wanted to target applications that had the kinds of electric and thermal loads that we knew would support CHP, based on what's there existing and also other work that we've done, other load studies.

But we were focusing in on areas that had both electric and thermal load, using a couple of different databases on facilities within the state.

And, the other side, we needed to get electric and gas rates for the study. We characterized rates for the three IOU's and the two largest municipal electric system, and developed a bit of a more general picture on natural gas prices in the northern part of the state and in the souther part of the state.

So we first characterized the applications, and then the rates, and then in the middle here we looked at the different technology options as a function of the size of the facility, from 50 kilowatts really all the way up to more than 100 megawatts.

And so we collected information on the cost and performance, emissions, and operating costs.

And with these pieces we had an economic comparison model that would tell, within a given market segment, what the payback would be for CHP. And based on that and a model of customer acceptance we came up with the CHP market deployment scenarios.

It's described in the report, so I'm going to go on to the results. The technical market potential is a bit of a, it's an odd number in that it's an intermediate calculation in our process. It represents the target applications that we've added up that say these facilities could possibly support CHP.

It says nothing about the economics, and it's really just the initial target that goes into the economic competition model.

And again, we developed the technical potential at existing facilities based on analysis of commercial industrial facilities, databases, based on the target applications that we selected.

And the technical potential for new facilities that would grow between now and 2020 was based on an evaluation of growth rates by sector within the state.

So, we segmented this into three specific markets. What we're calling traditional CHP, where the thermal energy is used as steam or hot water. And we split that into two high load factor applications that are basically running continuously except for maybe short downtime for maintenance or whatever.

And then low load factor applications that may be running two shifts or even one shift, but they're getting less use out of the equipment.

And we had to dis-aggregate those because we were using a differnet economic model to compare the performance of those.

The second big market we looked at was adding cooling to CHP, and there were also two subsectors of that market. Part of the traditional CHP market, in the commercial sector, you could add electricity and hot water or steam, or you could add a system that had plus cooling.

For example, in a hospital, it could support a traditional CHP system or it could also support one with cooling. And we wanted to look at both of those alternatives but not double count the result when we got to the end.

So the incremental applications are in

sectors that we're already looking at, but could maybe provide additional capacity if you added cooling. And I'll talk a little bit more about that.

The last market we looked at was the export power market, or facilities that had an excess of thermal load, steam load, typically large industrial plants.

And the morning session, particularly refineries and some other speakers, talked about situations where they have quite an excess of steam load and they have a capability to export power to the grid. And they also talked about a lot of restrictions and problems with that market.

But these were the three specific application markets that we looked at, and each one of those had a different economic comparison and assumptions to it.

The sum of the total remaining technical market potential within these three markets ar shown with two different splits in these two charts here. About two-thirds of the remaining technical potential is in the commercial market, and one-third is in the industrial market.

This doesn't necessarily reflect how

economically valuable it would be in either of these markets, but it reflects the fact that the commercial and institutional markets are much larger than the industrial market and have a much greater amount of untapped potential.

We also, the next slide over shows the comparison between the existing facility -- so the light blue are all the facilities that are out there now that could support CHP, and the purple colors is the new growth between 2005 and 2020.

The other thing I want to comment here, is that in the export market, that market is focused on some pretty large smokestack industries that are not growing. So the growth potential there is very low.

I want to focus in on what were the targets within the traditional market. I'll start with the industrial sector. Again, we're looking in defining this market as onsite use of electric and thermal energy.

96% of the existing CHP, and also about two-thirds of the remaining potential are concentrated in six major industries, and those are food, refining, metals, paper, chemicals and wood products.

And in the industry as a whole there's an average already about 60 percent market saturation. So the industrial sector has been the largest component of the existing CHP market, and there is significant remaining potential.

But as you can see, there's also significant market saturation that's already occurred in these markets that will limit future penetration.

In the commercial and institutional sector the situation is a little different. The existing market penetration has been quite a bit lower, so the remaining potential, as I said before, is two-thirds of the total.

The top applications are education facilities, which are also the number one commercial or institutional application, both nationally and in California.

Office buildings, which are not now a really excellent source or target, but there's just so many of them, that they represent a large part of the target.

Health care and hotels, round the clock operations, high thermal loads, characterize those as good applications.

So that describes the traditional markets. The additional markets we looked at, the cooling market was about 7,300 megawatts of potential. Again, some of that is already included under the traditional market, so the net increment would be about 4,000 megawatts.

The new markets that we looked at, skipping down here, were specific applications that weren't part of the traditional CHP target markets. We added in applications such as post offices, airports, movie theaters, big box retail, food sales and restaurants. And that potential was 2,800 megawatts.

That 2,800 megawatt figure is specifically for the CHP electric component. But with cooling you're backing out on electric air conditioning or in some cases refrigeration. So you're getting an effective additional 10 to 18 percent reduction in electric capacity due to the reduction in electric chiller use.

But when we're talking megawatt numbers in this presentation we're talking about what actual electrical output there is from the system.

This final market, what I call the export market, 5,200 megawatts, we looked at the top 100 industrial facilities in the state. They're a handful of very large refineries, chemical plants, food processors, that have quite a bit of steam load.

And a lot of these facilities have CHP now, but not all of them have maximized the potential based on their onsite steam load. So this estimate of the potential was based on the steam load and meeting all of that and exporting the power.

So what happens, in some cases now they'll have small single cycle turbines, maybe 20 to 40 megawatts. If they put in combined cycle plants the steam load might support a couple hundred megawatts or more from that facility.

So this market, I think, is very important. As we get into later, we're not considering it as part of the base case, it's one of the additional cases that we discuss later.

So I'll just go through the general assumptions that we made for the base case. We wanted to have a general consistency with our rate forecast with the IEPR 2003 assumptions, but adjusted for current market conditions.

In the best possible world we would have had the output of the work that's being done now for the 2005, but what we tried to do was talk to the people working on those and anticipate a level and come up with prices that would hopefully be consistent with the final results in those activities.

And so in the gas area we're looking at a continuation of high natural gas prices, but with some early declines in the next four or five years, followed by prices increasing in real terms through 2020, and the actual pricing assumptions are in the report and at the end of the handout.

In terms of electric rate assumptions, the assumptions were declining prices for the IOU's in the first five years, and then constant real delivery costs after that point.

And generation prices rise with gas prices after 2010, based on the share of gas production or the assumed share of gas production in the output.

In terms of the technology assumptions we made, in the base case we're looking at only incremental technology improvements. Basically how these systems might evolve without the public funding, the federal programs or EPAG. Program targets were not included in the technology performance.

In terms of emissions, this was a critical issue relating to the 2007 emission standards being accelerated in the south to meet the .07 pounds per megawatt hour for NOX.

And so we assumed that this would go into effect immediately in the southern part of the state, but the emission limits and schedules would be unchanged in the northern part.

In terms of the incentive programs, the self-generation incentive program was included in the base case as recently modified and extended to 2014. And we also included, it was mentioned in the end users panel, the incentive gas transportation price for CHP was also modeled in the base case.

But all of the power we looked at was onsite use. None of the large export industrial projects were included.

This chart summarizes the onsite technical potential from existing facilities and from new growth between 2005 and 2020, and then in this column it shows the results of the market penetration analysis.

So these figures, in this column, represent cumulative projected market penetration between 2005 and 2020. And the base case forecast then is just under 2,000 megawatts of added CHP. If you're quickly trying to add this column, again this footnote, the incremental cooling mark, it's 439 megawatts, only about 30 percent of that is actually additive to the total.

So, I put each of the totals up here, but when I added them up only 29 percent of that is put into the total.

The average penetration share, in going from the technical potential to the penetration share, range from about 6 to 9 percent of the market penetration in the base case.

This is, it's not year by year, but we forecasted in three time periods -- 2005 to 2010, 2010 to 2015, and then 2015 to 2020. And these are, again, cumulatives.

So there was a bit of a slow start in the first five years on penetration. A lot of that had to do with the assumptions on the emissions requirements in the south, and whether or not the small systems would meet that.

And this is just another cut at the

results. We looked at it, again, by utility and by region of the state, and this shows the different size ranges we looked at. We didn't look at anything under 50 kilowatts, all the way up to big project over 20 megawatts. And this is the onsite potential.

Within these first three columns here, or actually completely within the first two, those are SGIP eligible projects. Our assumption was that all projects that went in between now and actually 2015 got the SGIP incentive that was appropriate to the technology type.

And also within this one to five megawatt area, the first megawatt of those systems was also given the incentive. So a five megawatt system would get an incentive on the first megawatt of their output.

There's quite a bit of penetration then in these sizes. But a lower penetration of the larger sized systems was not so much that those systems were uneconomic, they actually are, percentage-wise, more economic than the smaller systems, but the remaining technical potential of onsite CHP for these large systems, and pretty much most of those ar industrial, is more limited than in the smaller sizes, which includes most of the commercial applications.

From the base case, and also from all the scenarios we did, we measured not only their cumulative capacity, but we provided benefit measures for the policy part of the study.

Three measures on the base case, by 2020 we estimated a cumulative to 400 trillion BTU cumulative savings due to CHP. That would result in a 2,500 million ton cumulative reduction in CO_2. And in terms of the net customer savings, a net present value of $451 million from that output.

Some observations on the base case. Again, we restricted the very large industrial export potential from this case, so that's not included. This second bullet is worded a little strongly or incorrectly.

Our assumption in putting the technical characteristics together was that the small reciprocating engines and small systems did not meet the 2007 phased emission standards until 2010. So in the southern region, in the small sectors, in those technologies, there was resulting no penetration.

And there are issues about technologies that maybe can meet this at a price, but that was the assumption in the base case.

In other cases that we looked at, the high R&D case with accelerated technology development, technologies that we modeled were able to meet this emission requirement.

In terms of utility by utility, the most restrictive market for CHP was the LADWP, because of their effectively much higher standby cost and the rates that they had. So the penetration within their service territory was comparatively lower than in the other IOU's, and also in SMUD.

In terms of the SGIP incentives that actually get paid out on this scenario, a total eligible market penetration of 678 megawatts goes into the market. 512 megawatts of this are in systems less than a megawatt, and the rest was for payments on the first megawatt for systems between one and five megawatts.

So the total incentives paid out was $407 million, which is within the current annual funding limits for the program. I believe they are not exceeded by that base case.

In terms of the cooling configuration,

we saw a little over 600 megawatts of CHP in the cooling configuration penetration. And again this would save an additional 70 to 90 megawatts of peak electric capacity by displacement of electric driven air conditioning.

What we're supposed to be discussing when I'm finished is setting the stage for the base case, but I also wanted to touch upon the alternative scenarios that we ran and kind of lay the groundwork for the next presentation that Snuller Price and E3 will be making.

So, once we established the base case and had agreement that reflected reasonable market expectation then we looked at alternative cases.

The first case was more or less removing the existing incentives, the SGIP program and the incentive gas transportation rate. And so that was a scenario.

And then moving forward on the positive side, we looked at the addition of a number of policy incentives. What happens if you facilitate the export market, provide payment for CO2 reduction, if the utilities provide payment for T&D support, for thermal CHP production credit, and if you went in and expanded the SGIP eligibility.

In addition we looked at an alternative CHP technology case, more rapid deployment of advanced technology.

And then finally, in the morning session Nick Lenssing showed consumer acceptance curves, 50 percent of people would reject a two year payback and so we looked at a case where an increase in consumer confidence and project performance would change the way consumers make decisions about CHP and make them more willing to accept let's say a socially positive discount rate on a project, and not be as risk averse.

So we improved their acceptance criteria or broadened it, and also allowed for more rapid deployment. So those were the variables we were adjusting in the alternative scenarios.

And I'm not going to discuss this in detail, but we ran 8 different cases and the policy implications of these cases are the focus of the next presentation.

But in general, after the base case, we removed the incentives, and if you remove the SGIP and gas price incentives you get a fairly significant reduction in expected future market.

In the case called moderate market access we allowed the facilitation of export CHP. That had a very significant impact in that there was a small number of very large plants, you could get an additional 2,400 megawatts of capacity based on the facilitation of exports.

Aggressive market access added to that above scenario, a CO2 reduction payment and a T&D support. An I won't get into the details of that I'll let Snu talk about them. And then we looked at other scenarios.

And at the bottom, let's say you had rapid technology deployment, facilitation of export, CO2 credits, T&D credits, and this creates such a positive environment that you get a higher consumer response, less risk averse, more willing to accept payback of three, four, five years. Then, the future market there was over 7,000 megawatts.

So that was our focus on the market, to look at the market and do the analytical market analysis. I would like if possible to focus the questions on the base case because the next presentation is going to get into all the different variables and what they mean and what happens.

So, if there are any questions on how we set up the analysis and the results of the base case, that's what we'd like to focus on.

MR. CONTRERAS: Hi, I'm Jose Luis Contreras from Navigant Consulting. Thank you for your presentation.

My question was, on page 13 you have the table of penetrations in different sectors. And the penetration share, can you tell us how you got to that number in terms of estimating the penetration in each of the segments?

MR. DARROW: So that's slide 13? How we arrived at this. Well, if I interpret your question I guess is what is the interpretation. Because the math is this divided by that, that's about 9 percent.

But what I was trying to get at by showing that number was, first of all, an issue that was brought up in the consumer panel, which is there may be a lot of opportunity out there, but very few people are going to actually end up implementing these systems, it's a small percentage of the total.

So I was trying to show what the basic

level of acceptance was in the base case. And these numbers are quite low. And you can see, if you reduce the load factor you reduce the penetration share, because you have fewer hours of the year to recover the cost of those generating assets.

And actually in the cooling specific markets those are also a low load factor application. Those, the potential was also lower. When you get into -- and I didn't mention this when I was there -- but when you get into these large sizes the penetration rate in the over 20 megawatt systems was 22 percent of the technical potential.

So those large systems are pretty much economic systems and you get a higher penetration of the potential. So I hope that answers the question.

MR. BRENT: Richard Brent with Solar Turbines. You mentioned in one of your slides that the environmentally preferred advance generation program wasn't calculated into the potential for combined heat and power.

Considering private industry, the Energy Commission and the federal DOE spent considerable sums on trying to reduce the amount of emissions criteria pollutants out of these primary technologies, could you hypothecate then what that may do in terms of spurring on more CHP with EPAG oriented generation?

MR. DARROW: Sure. We did look at a high R&D case, and I can't say that the acceleration that we looked at for each technology that we could tie it specifically to this program or that program, but certainly it reflected the work going on I think in DOE and also EPAG to try to reduce cost, improve performance.

And so we put reduced cost and improved performance and the resulting impact on the high R&D case is -- and I don't have the number in front of me -- but it's about an additional 5 to 600 megawatt penetration.

And when you consider that anytime you improve the market you're going to improve customer confidence, then you can say well, we're actually going down to the bottom.

And so the R&D alone provides a certain improvement, plus you're instilling confidence in people that the technology is going to work and be reliable, they're not going to have hidden costs if they sign up, and you get a higher degree of acceptance.

So we didn't want to include all of these things in the base case because we wanted to look at the impacts of controllable variables in these other scenarios.

MR. BRENT: As a follow-on, does that assume R&D at the level it is today, or does it look at increased or decreased R&D dollars focused on supporting that confidence level that you talked about in high deployment?

MR. DARROW: You know, we set this thing up so that we could analyze R&D issues, and we got swept up in a huge policy maelstrom. And we really didn't exercise -- we only ran two R&D cases, so yo can't really make a lot of individual judgments about things that way.

We really were focused more on the policy side of this, but we included R&D and improved technology in a general way.

MS. TURNBULL: I'm Jane Turnbull from the League of Women Voters. Granted our California culture doesn't really include district heating as part of our culture.

On the other hand, the Scandinavian

countries have used CHP very successfully for a lot of years because district heating is a part of their culture. Did you automatically write off district heating as something that's not applicable for California, or would there be scenarios where it would be acceptable?

MR. DARROW: I think a lot of, or some very large campus college systems have some aspects that resemble district heating, but in terms of the specific market of aggregating individual homes or apartment buildings and providing steam to them, we didn't consider it.

There's quite a difference in the equipment that's there, there's really no hydronic heating, and there's less of a hydronic load. You could consider it for steam for air conditioning.

But we were looking pretty much building by building making their own decisions on their facility requirements, and we didn't consider the aggregation of say a whole area that might be on a steam system and be providing air conditioning.

Because I don't think heating would make a lot of sense in the California climate, but air conditioning --.

MS. TURNBULL: Hot water?

MR. DARROW: Yeah, hot water would be --
MS. TURNBULL: Certainly farms. I"m thinking of farms, wash down water for farms, hot water. But --
MR. DARROW: The simple answer is we didn't include an aggregation of facilities. We looked at individual facilities, and if there are applications and things that you can consider in addition to this it would be an addition to what we looked at.
MR. RAWSON: Any more questions? Okay, why don't we move along. Thank you, Ken.
The next part of the presentation is going to be by Snuller Price, who is with the Energy and Environmental Economics, Incorporated. They are one of the other team members that was pulled together for this project, with EPRI.
And he's going to talk about the differnet policy scenarios that were developed and what the uptake impacts were of these different policy scenarios and what some of the key drivers are of those. So, Snuller?
MR. PRICE: Thanks, Mark. What I'm going to try to do in about 45 minutes is walk through some of the policy analysis that we did.

In working on the policy aspect obviously we were in close coordination, reasonably close coordination with the other parts of our team, the end user research that EPRI Solutions did, the market analysis, the penetration analysis that the EEA folks did, and we were working on policy to try to see okay, if we changed the base case with new policies, what policies looked good.

I'm going to talk a little about the criteria we used for well, what is good. I'm going to talk bout the policy options that we considered, and I'm going to talk a lot about the different sort of stable of viewpoints of the different policies that we've proposed.

Because I think the stakeholder perspectives are really important to this analysis. ?This is a public workshop. I look at the Q&A section of this to get everybody else's feedback is really an important aspect of this, as well as with the written comments.

So, I definitely encourage that part of this, sort of look at it as a stakeholder analysis.

The other thing I'll say before getting

into this is that there's a lot of complexity in the slides, and I'm going to try to touch on some of the complexities and I'm going to really look for comments on those as well.

But I hope we're also going to be able to get to some of the fundamentals that we came out with in our research that I think are important and definitely address in this amount of time.

So, the policy research approach, quickly, was first to sort of develop the goals of our policy ideas. What are we going to try to do? Then we went sort of to the drawing board and developed a list of policy options. This the laundry list, the universe of things that we could think of that would sort of push our goals.

That was done based on the experience of our team, based on the EPRI solutions, interactions with the end users on some of the issues that they came up, and we developed the whole list of options.

We then developed from this whole laundry list of options policy portfolios. Those were groups of ideas and policies that could be implemented and went together and kind of formed a coherent policy with a theme.

Then we did both qualitative and quantitative analysis on what would happen under that policy portfolio. And that was done in conjunction with EEA in terms of well, what would happen on penetration, and those were some of the numbers that Ken just showed.

And we also looked at individual cost benefit analysis of individual applications, both for the CHP owners, the utilities, as well as societal perspectives. And we'll be seeing that.

I'm going to wrap up with conclusions and R&D research.

So, what were the desirable attributes of our CHP policy options? What are we trying to do?

And the first thing that we're trying to do with the stakeholder approach is really focus on stakeholder goals, which are, as we sort of emphasized, higher efficiency of the state's energy resources, positive environmental impact.

We also have and were very cognizant of impacts on utility rates and cost shifting to different customers within the utility. So we wanted to take not just higher efficiency as a goal but something that would promote the best projects in terms of projects that are really well-suited to capture a lot of waste heat, projects that have the most benefits in terms of economics, but also something that's relatively easy to implement.

So one of the easy traps to fall into when you have the whole laundry list of potential policy options is that some may sound good but very difficult to implement, very difficult to actually get into the field and make workable.

The last couple, we wanted to have relatively low incentive payments, and one of the themes that you'll see coming out of our slides I think is that a lot of the payments for CHP and to encourage new options are based on value that the CHP provides the system. I think you'll see that.

And that gives us a relatively low incentive payment, and also gives us what we think is a relatively realistic exit strategy for something that someone might call subsidy or incentive, and so on.

So with those lists of desirable attributes we started this exercise of developing a whole laundry list of policy options to promote

CHP and CCHP. And this slid and the next one is a whole long list of what those are.

They are organized into sort of categories. So, for example we have a number of policy options that we considered that addressed SGIP modifications, the self gen program.

We have a number of policy options that we considered that address resource adequacy. We have a number of incentives or a number of policy options that address investor owned utility incentives to become a partner in the CHP projects. We have a number of things that looked at rate design changes.

For each of these policy options we looked at some of the barriers that end users identified and some of the barriers that we're trying to address that are thought to be barriers to more CHP, CCHP adoptions.

So for example, promoting high value CHP options, reducing capital costs, increasing operating benefits, reduced hassle, siting permitting.

A lot of these issues have been talked about in the morning session by the end user panel, and sort of and so on.

And, for each policy option, obviously we have a checklist of okay, what options are addressing which problems.

I know it's small font for everybody in the room and if you don't have a handout it might be a little difficult. I don't want to go through every combination for every policy and attribute, but what I want to make clear is the structure of how we went about organizing all of the things you can do.

On the second slide we looked at a number of options on marketing, and somehow making CHP, CCHP more attractive to end user customers.

We looked at state tax ideas that may provide additional benefits for an end user that adopts CHP, CCHP. I'll come back to other actions. That was sort of a catch-all for anything that we couldn't easily categorize.

R&D, okay, we looked at well, maybe we could do investment on the R&D side, a policy portfolio on that.

And finally we looked at portfolio standards ideas, and we'll be talking about that later as well.

So with this laundry list of all the

policy options and all the things we could do identified and what sort of issue they addressed in the CHP market, we started to package together policy portfolios.

We weren't going to just do one measure and sort of a band-aid type of approach of one measure and then leave it at that. We were going to package together a number of policies that had coherent theme and identify with each portfolio those policies that are really core to that policy portfolio and those that are supplemental and would be nice to have in addition.

These are the same portfolios that Ken was showing in his presentation in terms of the estimated penetration and the total number of megawatts we would get through 2020 in California under each portfolio.

I'm going to go through them in a little bit more detail, and just try to explain what we were trying for in that policy portfolio.

First one, first policy portfolio, the base case, I think was pretty straightforward. What we were trying to do there is model as best we could the trajectory of existing policies that are in place in the state and what will happen.

And EEA's analysis shows about 2,000 megawatts of penetration through 2020.

The second case we tried to look at is well, what happens if we just eliminate SGIP, if we remove the preferential gas transportation tariff fees and just get a baseline trajectory of what happens.

So this is the regressive policy approach so we can get sort of a baseline of how much these things matter.

And the third policy portfolio we called moderate market access, and where we were really going here is trying to improve access to the wholesale energy markets of combined heat and power insulations.

We heard a number of things this morning from the end user panel about the difficulty of scheduling with the ISO and the rules that basically require the CHP to have a lot of the same infrastructure as a central station plant, but even down to the smallest combined heat and power unit.

So with moderate market access portfolio we were trying to eliminate some of that. And the way we were conceptualizing the moderate market access is that the utility would purchase the energy as available from the plant. And that's pretty much the four policies of moderate market access portfolio.

Under the aggressive market access portfolio we have the same wholesale export policy idea, but then we've added in a dish and the idea of selling generation capacity, to the extent that generation capacity markets are developed in California, and transmission and distribution capacity.

So we really we're then, with our CHP unit you can provide a number of different services, both energy but also generation capacity for resource adequacy and transmission distribution capacity.

Under the fifth policy portfolio we really focused on not the market access but the alternative, which was pretty much the existing structure but expanding SGIP. And we looked at expanding SGIP in two ways.

One way was for larger CHP installations. That was in part from the EPRI solutions feedback, from the customer interviews about desire for having larger units qualify, as well as the level of the payment.

We also looked at, under the increasing incentives portfolio, a production tax credit, so that you would get paid per production as you went along, as opposed to the SGIP incentive approach, which is an upfront payment.

The sixth policy portfolio were a group of policies designed to streamline CHP installations. We heard a number of things from the end user panel about the difficulties of permitting of interconnection, of different types of interconnection, and so we were trying to look at ways to facilitate the whole startup of those.

From EPRI solutions and customer interviews, this didn't seem to be that big of an issue, for their interaction with the customers. But nonetheless this policy portfolio looked at that and what sort of policies would promote it.

The seventh policy portfolio, increased R&D funding. So here we're not looking at changing the actual mechanism and the actual incentives that the CHP customer gets, but trying to improve the cost and performance of the CHP units available to the market.

In the eighth policy portfolio, the high deployment, we started to combine and get an upper bound on potential penetration by doing aggressive market access but also increasing R&D funding and also doing some streamlining to improve customer acceptance so that we could really accelerate development of CHP.

And finally, under the ninth policy portfolio, we looked at portfolio standards. And for our model there we were thinking about the renewable portfolio standard in California and something similar to that where we'd set up target penetration level as the goal, and then we would vary the incentives to be able to reach so many megawatts by such and such a time.

So for each of those nine policy portfolios we addressed each in a different way, as I'm going to try to clarify how we did that. We did two quantitative analyses.

The first quantitative type of analysis were the results Candice presented from the EEA in terms of penetration, what are we going to see in the state over time through 2020.

And we did that penetration analysis on portfolios one through eight. And we didn't do a penetration analysis of the portfolio standard because portfolio standard starts with the penetration and works backwards. So the penetration in the portfolio case would be what you start with, or what you mandate as the penetration goal.

The second type of quantitative analysis we did was to look at the costs and benefits to each of our stakeholders for an individual CHP installation.

So, a commercial customer is going to install a reciprocating engine with waste heat recovery. That would be an example of one application. And then we looked at what is the CHP owners costs and benefits look like, what do the utilities' cost and benefits look like, and what does the sort of state net benefit look like.

And I'm going to be talking about some of those charts, some of those analyses. We also did some qualitative analysis. So for each of these policy portfolios we went through our list of stakeholders in the state, and I'll talk about the perspectives we took.

And we tried to give it an assessment, well, does this policy make sense, is this going to help my perspective or not.

And finally we evaluated portfolio standard policies, and I've got some pros and cons of the portfolio standards approach to share.

When we line up all nine of these, I guess this is the first eight -- and this is a little bit like jumping to the punchline and the answer -- we quantified a number, the impacts of each policy portfolio in a number of ways. And I want to spend just a little time walking through the results.

On this chart we've got, for each of the policy portfolios we've got the net benefits to the CHP owners, these are the green lines. So this is the net present value of the savings for that customer under that policy portfolio.

We've got the next present value of the net benefits, they're all negative so we're calling them losses, to the utility for having behind the meter CHP installations. And finally, we've got a total societal benefit.

So we've got customer savings, we've got utility operating margin losses, we've got, with the triangle, society's net benefits.

On the right hand access we've got the cumulative penetration through 2020 of each of the policy portfolios. So, for example in our base case we've got, here's our 2,000 megawatt number.

In that case we've had I think 400 and something million net present value of customer benefits, and something on the order, I forget what the number is, but it's like, about 700 million or so present value operating margin losses.

And I'm not going to go through each policy portfolio and talk about the numbers, I just want to talk about some of the key things that stand out. Clearly, in all the policy portfolios, we have sorted an order of total penetration.

And we've got the base case, we've got a set of policy portfolios that kept our existing wholesale export conditions, which we characterized as difficult, and facilitated export. So all these policies allow facilitated export.

So clearly we're seeing highest penetration when we can have those really big units at those top 100 industrial sites putting more energy and sizing their units for the onsite thermal needs and exporting excess energy, and we get a lot more energy production.

Because of that we get a lot more energy production at a higher efficiency than central station plant, and we can see from those portfolios that the societal net benefits are considerably greater. You can see that those are significantly more dollars from a societal perspective.

From the other policy portfolios, one I wanted to point out on the increased incentives. One of the issues about increasing the incentives is that we're paying a lot, we treated the additional incentive payment as a cost from a societal perspective.

So we're getting more CHP installations but we're paying out a lot of the societal benefits back in incentive payments. So the participants are better off, but from a societal perspective we're getting down to the more break even perspective.

In terms of the relationship between the owner savings and the utility operating margin loss it's pretty proportional for a lot of the incentives in terms of the streamlining policy portfolio, in terms of the high R&D, in terms of the increased incentives, maybe a little bit different ratio.

One of the things that we were really trying to get to with this stakeholder perspective is win/win. We want to be able to make all of our stakeholders better off with the right policy, because that would just make life a lot easier.

And what I think is important, and you'll hear me say it again at the conclusion, is that I think these policies that provide a payment based on the services, either wholesale energy in the moderate market portfolio case, or wholesale energy and wholesale capacity and T&D capacity in the aggressive marketing case, provide significantly greater penetration and significantly higher societal benefits and relatively, in terms of the ratios, lower losses than the other utility customers.

And the reason for that is we're starting to coordinate the CHP operation with the utility system operation, so cogen is on during times when utility system costs are at the highest. And we'll be talking about that a little bit more.

This slide, it's the same slide, it's a

little less interesting because it's just numbers, but it's the same numbers that were charted on the previous slide. With the addition of the total CO_2 saved.

So, the CO_2 saved, in terms of millions of tons, is pretty proportional to the penetration of CHP. So, as you get greater penetration you'll see more and more tons. In our high deployment case that's 120 million tons of CO_2 reduced through 2020.

One of the quantitative analyses that we did was to look at individual installations of combined heat and power, and sum up what the costs were and what the benefits were for each of the stakeholder perspectives.

This is an example of the tool that we're using to weigh those costs and benefits for one of those cases. And what I thought I would do is walk through a little bit in terms of what costs and what benefits can we look at for each perspective and then in the handouts there are a number of different cases and I thought I would go quickly through those once we kind of got the overall structure clarified.

This is an example for a reciprocating

engine, 300 kilowatt, using 2005 operating cost assumptions in Southern California Edison's territory on an industrial tariff. So that sort of defines what this application is.

And then we looked at, for that unit, what the levelized net benefits were from the CHP owner perspective, from the utility/non-participants perspective, and from a societal perspective.

Now, the reason why I've labeled this utility/non-participants is that if the bill reductions that the customer sees are greater than the savings in terms of the variable operating costs from the utility there's a sort of net operating margin loss.

So the question is how do we make that up? You could make that up with utility shareholder earnings being reduced, that would be the utility perspective, or you could make it up, which is much more likely, through increases to rates to non-participating customers. So that's why we've got the utility/non-participants.

So, for this example with this set of assumptions, what we've got in terms of the benefits for the CHP owner, which include that utility avoidable rate piece, the value of the waste heat, and the SGIP incentive that that customer would get, in terms of the benefits, and the cost of the capital, the fuel and the maintenance.

And when we compare those, we get a life cycle benefit of almost five cents, with this set of assumptions. That translates to a 2.11 year payback on that customer's invest. The 2.11 year payback, where we did the penetration analysis, you saw Ken's number of percentage of customers that would adopt a different payback periods, so, for example a little over two years it was something like 50 percent or maybe 35 percent of customers in that situation would adopt, and so that would be added on to the penetration analysis.

From the utility non-participant perspective the benefit is you reduce wholesale energy purchases, which, with the forecast we have of future wholesale energy prices, was about six and a half cents.

In terms of the costs we had the avoidable rate for that customer, which was about 11 cents, plus the SGIP incentive, gives a net negative of about five cents per kilowatt hour life cycle.

And then from a societal perspective it's a little closer, it gives us a one cent positive. And what I've got here is, in terms of the benefit, the value of the waste heat, the value of the wholesale energy, and the value of the CO2 emission reductions, which is this very small bar at the bottom. And we'll come back to that.

And in terms of costs I had the financing and capital of the unit, the fuel, and the maintenance costs.

So, from a societal perspective this unit, recovering this amount of waste heat, is one cent positive. It gives quite a bit bigger positive than CHP owner, and from the utility perspective it's negative.

I want to come back to the CO2 value. What we used there was a number of $8 per ton CO2, which is the number that has been adopted for long-term resource planning decisions in the state. So I've added that on as a benefit.

We looked at a number of policies that sort of deviate from the current policy, which is actually a payment for the CO_2, using that same amount and that same number, the $8 per ton.

Clearly the results that you get in this kind of analysis depend almost completely on your assumptions of costs and benefits going forward. And knowing that, what we did was a lot of sensitivity analysis around what fuel prices are going to be, what gas prices are going to be, what capital performance and so on.

And that's why you can see in our spreadsheet here, we have all these slider bars so we can say well, it's actually no $1,350 in KW, it's actually $1,800, and you can move that up and re-compute.

So I think the major assumptions here give you an idea of how we did each individual analysis. This is for that 300 KW reciprocating engine. If you take the current cost of molten carbonate fuel cell you'll get a very different picture of course.

The CHP owner from this perspective is about zero. It give you a seven year simple payback. It's a little more negative for the utility because the SGIP is bigger. From a societal perspective it's a negative value, assuming current cost performance of a fuel cell. We all know these are not exactly at Home Depot.

If we look to the future, though, first we're going to change the paradigm and go instead to base case. We're going to look at this aggressive market access, so now we're going to be able to export energy, able to pick up a T&D credit and so on, and we can re-compute all these costs and benefits.

And we look at a CHP owner as slightly positive now, but we haven't really changed a whole lot. The utility is pretty much unchanged, societal is pretty much unchanged for this application.

As we move into the future and look at a fuel cell and -- and these are just examples, we got into a lot of different technologies -- and look at how this changes over time with decreased cost and increased performance of fuel cell we start to see well, CHP owner is looking now at rather than six plus years payback it's down to five, the utility perspective is still pretty much unchanged, societal is still a little negative.

Finally, I wanted to show what happens with a bigger unit. A large amount of the energy produced in these export market cases, almost all of it, is with these much bigger turbines located at a refinery or other large industrial site. And this is how the cost benefits lay out for that type of example.

I think that gives you a flavor of the costs and benefits analysis we were doing on individual applications. I wanted to sort of change and talk a little bit more about the qualitative analysis that we did on the different policy portfolios.

From just a cost and benefits perspective you can add up the cost, add up the benefits, but I really want to get back to this idea of something better off for everybody, or at least as close as we can.

And so what we wanted to do is consider each of these policies from the different perspectives. Perspectives we looked at for this type of analysis was the customer, the CHP owner, the facility that owns it, the utility/non-participants, the state society.

We also wanted to look at each of these policies from the small user advocate type perspective. So what's going to happen to the utility rates for the smallest customer, smaller residential customers, and are they going to be impacted with higher rates?

We want to look at are rate levels overall going to go up because of our policies. And of course the reason why we wanted to look at each of these perspectives is that, if any of these policies sort of move closer towards adoption there's going to be a lot of comment and there's going to be a lot of discussion about each of these from each of these groups.

And we wanted to, as part of the public workshop and the stakeholder workshop, start putting out there what we think some of those issues would be for each of the policies.

Now, that said, I don't want to put words into any particular stakeholder groups' mouth per se, and definitely look forward to comments from different groups that may look similar to the perspective that we're taking here, and get feedback.

So this is intended for starting discussion, definitely not the final line. So, with that said, let's look at each of these policy portfolios, each of these sort of stakeholder perspectives, and think about what each would be.

Later on this afternoon we're going to have some discussion from the utility folks to definitely get their input and perspective on some of these policy portfolios, and I think the way we chose the policy is pretty much universally they make CHP adopters better off.

So I think universally we have a yes for participants. From the state, we'll talk about that. I also want to emphasize this impact on the smallest customers and impact on energy costs overall.

For the first policy batch we want to look at, it's the moderate market access portfolio. So this is just the facilitated wholesale energy export type idea. That's really the only policy we looked at under this portfolio.

And what I wanted to get to, is first sort of describe how we envision this. What this policy portfolio does is basically take excess electricity from the site as available and pay at the wholesale energy price.

So this is different than a contract with ISO where you would schedule to deliver so many megawatts over so much time. This would be something where, I've got excess electricity and it's almost like net metering but it's at the wholesale price rather than at the retail price. That was the idea.

Now, I think participants like that, especially the big ones. The state, I think, would like that, because it gets towards these goals of encouraging more production at higher efficiency levels.

We think that the small user advocate groups would like this because we don't see a big rate impact from this type of policy. We're paying the market rate, which they would be paying for anyway. So I think that would be fine. And for the same reason from the ratepayer advocate perspective.

From the utility perspective, since they are the buyer of the energy as available, this creates some issues. It creates some issues for them in terms of okay, now they've got to have other resources to do balancing.

We heard this morning about a case in Denmark where this got to the sort of extreme, and you have all of the local districts being able to produce energy as however they want, and the grid has to manage it. And at their level they had over 50 percent penetration.

Clearly, as you get to a really high penetration as available issue might rear up, but we think now that it may not be such a big issue.

Under the aggressive market access portfolio we've taken this idea another step farther, and we've added on, well this first idea, of T&D capacity support payments. Which is something that's not new, and it's been talked about at the CPUC.

And implementing the T&D capacity support payments is something that's got a lot of complexity to it and I think we're going to be talking about it even more tomorrow.

But for the purposes of this the idea is to pay for capacity that the CHP provides at a level that represents its value. So there's a lot of difficulties in structuring that contract and matching exactly the payment to the value, incorporating it in with planning.

But for a policy level analysis, assuming that we can pay what it's worth and add that, it's a service CHP can provide, it's a perspective we took.

From the participants perspective, we think that the T&D capacity payments would be welcome. I'm going to skip back over to utility. Again, it's a medium here which means not a strong supporter, maybe not a negative, there's a lot of complexity in the T&D and in developing those T&D capacity payments.

And so I think that there's some caution there. And I think similarly from those that are looking at our rate levels and whether or not the money we're using with rates is well spent, I think all this complexity might also create some questions from our other groups in terms of our really, really, saving as much as we think.

Finally, the CO2 credit. And that would be a payment based on this $8 per ton CO2 saved. In terms of our economical modeling what we did was we looked at well, what's the average CO2 output of a central station power plant in California versus a cogen.

And because cogen uses its' waste heat and would reduce a boiler or some other end use, the overall effect on CO2 emissions is that it would go down with the CHP. And we took the amount that it would go down and multiply it by $8 a ton and that gave us the level.

We saw that, on the benefits column, it's a pretty small number. It's not zero, but it's a pretty small number, because of the sort of netting of the two.

In terms of the stakeholder perspectives on this, I think that participants would like it. They're providing something, cleaner planet, and getting paid for it. I think this goes sort of in the direction of the state goals, if we lay it out.

In terms of the small customers and the ratepayers we don't really know. I think, I don't think this is a big cost item, but then again you're paying something out of rates so small customer rates would go up in order to pay for an additional benefit for an industrial customer might have some issues, so I wanted to point those out.

But we're not really sure, because at the same time it is a pretty new environment. So, there's some tradeoffs, as in most of these.

From the utility perspective, I think it's gain medium, and this would depend a lot on how this is set up and whether the utility was on the hook to track how much CO_2 people were saving and how complex it would be to implement, because that could be quite a program to try to set up if you really got precise with it.

The third portfolio on this slide, increasing incentives, this sort of the, not the opposite but a different approach than the market access policies, which is we've got our existing system, let's increase incentives, let's get out to more customers with a larger cap on the megawatts size of the installation, and use what we've got and keep going with it.

From our stakeholder perspective the increasing SGIP incentives, well, obviously I think the participants would like it. I think you'd run into some problems if this is really a subsidy from the small users who are paying part of their utility bill to fund technologies that are really most suited for the largest customers in the state.

I think in terms of cost overall, if you keep those increases within reason, maybe from a ratepayer advocacy perspective it might be sort of more mutual. Again, I think the utility might be pretty neutral on that.

In terms of the other policies that we looked at, in terms of increasing incentives, not just SGIP but some other ideas that were on the table, the first one is a partial pass-through of interconnection costs.

And the way we were thinking about this is basically a portion of interconnection costs would become a utility investment, and therefore treated and rate-based and so on, and be part of the utility system.

If we're going to use CHP as part of California's energy mix, then maybe some of the interconnection costs make sense to have in our rate base. If, from that implementation perspective, customers are going to like that.

I think utilities, given the chance that that is going in for rate base and become part of the utility system I think maybe they would be neutral. I think that from small user advocate and ratepayer advocate it would depend on how much money are we talking about and how big a bill impact is that going to be.

If I can get a lot of environmental and other benefits because of that policy I think that may not be a complete non-starter.

The other two core policies in terms of the increased incentives portfolio was two different state tax credits. One was a production tax credit that we set equal to that $8 per ton CO2, and one was a capital cost credit that you could reduce your tax bill by some sort of accelerated depreciation of the capital purchase or something else at the state level to give you a tax benefit.

I think that the state tax perspective, if it's coming out of state taxes probably doesn't affect those that are looking at the rate levels so much. I think that the state would be neutral, if that's even possible, because of the fact that we're going to be taking money away from other things.

We notice that there's quite a few people outside of the Capitol down the way, I'm talking about the schools today. So when we start to get into competing issues and competing uses of state's money.

Finally, the last two, we've got streamlining CHP installations. And what we really wanted to go with this set of policies was to make it easier to get CHP done. We heard about this morning a number of cases where there was just difficulty for people to get through the process of permitting, interconnection, there's a lot of regulatory uncertainty also. There's a number of issues.

So this was a set of policy proposals to improve adoption rather than increasing the money or creating markets and so on, just streamlining what we have and see how that goes. I'm not going to go through each of these, I think they're pretty reasonably self-explanatory.

But, you know, the idea of creating CEC vendor certification list for example, so that when customers have people approaching them they can go look at the record of that company and they can look at the installations they've done and they're certified by the state.

Or free CHP assessment and auditing. So, why we do energy audits for example for utility efficiency program, why not do audits for and perhaps this exists to some level, but why not do audits for combined heat and power use for commercial industrial customers. To make opportunities that are there more visible.

Finally, our R&D portfolio. What this

is is spending more money to improve the technology costs and performance, and not really touching the other policy pieces that we have in place.

I thought that was the last one, but it's not. The Hybrid portfolio is sort of a combination of those that we've gone through before. We've got these wholesale energy exports, we've got the T&D, we've to the CO2 credit, R&D, we've got education, vendor certification, a number of different things to facilitate adoption.

And clearly from our analysis this ended up with the highest net penetration of CHP in the state. I think three or four times the base case.

Finally, we've got portfolio standards for CHP. And again, this, we only really looked at it in terms of the qualitative perspective, and I've got a slide coming up on it.

What this idea is to set the target level for CHP and adjust the incentives up or down so that we can reach that level.

In terms of our stakeholder assessment of the portfolio standards of CHP, we think participants would probably like it because they are getting an incentive but based on how bid for, that makes their project economic.

I think that the utilities won't like this, and the reason we put a no here is, the way we were considering this policy is putting utilities essentially on the hook to meet penetration goals. So this is another goal that they would have to hit, and I think that there would be, I don't know that they'd like that necessarily.

The state, I think, would be kind of neutral on this, and the same with the advocate issue.

Let's talk a little bit more about the portfolio standards pros and cons, since we haven't done a lot of quantitative analysis on that. I just want to sort of talk about it.

The general approach with portfolio standard would be to set a target level penetration and then let the incentive vary up or down in some way.

And the thing that I really like about the portfolio standard is that it allows you to vary the incentive level to just the right amount that makes the project economic.

So, for example under, in contrast, the

SGIP incentive, where we have the incentives already fixed, $600 per KW for a particular technology. And whether you'd need 300 for a project to be made economic or whether you need 800.

The thing that's neat about the portfolio standard is that, through some competitive bidding, you would get just the right amount of incentive, at least in theory.

The cons is that, the first one is that developing the competitive mechanism for bidding on that I think is complex. The first complexity is who's responsible for reaching the target.

The second complexity is that there's a lot of different technologies and applications. I mean, we've gone from 50 KW combined heat and power up to a 50 megawatt turbine at a refinery, so we've got this whole breadth of technologies and so on. It's hard to see how you would do competition across the, it might create a lot of complexity.

The second con about the setting the penetration target is it's difficult to specify what's the right amount of CHP. We've done all these estimates of market penetration, but really the right amount of CHP is a difficult number to put your finger on, particularly with the fact that natural gas prices are moving up and down a lot and certainly natural gas prices are going to drive the answer you would get in any type of economic analysis of what's the right amount.

So, once you pick a number it might move very quickly, so I think that makes it difficult.

And finally, I think a portfolio standard is really an incentive-based policy, and I think one of the core recommendations that we are coming with is to try to get policies that focus on payments to CHP for the value they provide, not necessarily, and let the market decide what the right penetration is and not necessarily focus payments on what is necessarily needed from a subsidy basis to make a project happen.

Now, that said, I think we, we're kind of looking at two different groups of policies. And I started out by saying we want to make sure we have an exit strategy and a clear picture of where we're going.

We used this diagram to show what we think makes sense, in terms of exit strategy. And what we've got here is, this is the total payment, on the vertical axis, to a CHP owner. And the bottom block, we've got those policies, call them modifying the CHP market structure.

These are the policies like the wholesale energy export, like the generation capacity or T&D capacity payments that are paced on services that CHP provides the system. And those can last on and on into the future.

In the meantime, I think that, particularly, depending on technology and application of course, we also need a incentive policy not unlike SGIP that basically gets adoptions, because we want to see and encourage more adoptions.

The idea being with this sort of market transformation type of perspective we would pay this incentive, and then we would ramp this down over time until all the CHP units that we're talking about are sustaining themselves on purely market based payments.

So that's the idea for the exit strategy. There are similar ramp downs in policy now in place, and we've seen SGIP come down. We've also seen, well, under SGIP we've seen renewables ramp down.

All right. I want to get to a couple of conclusions and take aways, and then hopefully we can do some questions and answers.

The policy analysis conclusions from our overall perspective is that this idea of facilitating the export of wholesale prices could encourage new, very large CHP installations. Right now those biggest installations are really=y sited for onsite, they're not sited as big as they could be, they could be bigger to meet onsite thermal requirements and then to export excess electricity.

So that was a big part of the impact and a clear division in terms of policies. Of course the societal benefits of that, significant production, higher efficiency, look really good. That really helps the state's overall energy budget.

The second point from the policy analysis I want to point out is that, given our current rate structures, all of these policy options result in losses in electric utility revenue greater than the savings to the utility.

We didn't find any cases where we could

not have to somehow increase rates or somehow get past that. Now, those approaches that also have benefits on the utility side, like payments for T&D capacity, like payments for this wholesale energy or resource adequacy capacity requirements do mitigate those.

Because you get more penetration of CHP and you don't increase utility losses, okay. So it's going in the right direction, but I can't say that we've gotten to win/win. That gets you closer, but it doesn't get you all the way there.

Policy analysis conclusions. Increasing incentives, encourage more CHP adoption alone decreases the societal benefits. If you count those additional incentives that you're paying as a cost that will decrease the raw societal benefits.

And also, additional installations with current policy structures does increase losses to the utility non-participating customers.

So, the take away recommendations, we think, are to support policies and encourage operation of CHP, to capture both customer side and utility side benefits.

I think that it makes sense to pay for

utility system services, based on the value they provide, and we think it's important to provide an excess strategy that ramps down subsidies over time as the technology costs improve.

That's the final slide.

MR. RAWSON: Yeah, just a little mechanics here. What we'd like to do, we'd like to have some Q&A now. And since the utility panel's going to be next on the agenda what we'd like to do is, if there are utility comments, if we could hold off because we want that to be the focus of the panel discussion, so if we could get.

MR. TORRIBIO: Questions okay?

MR. RAWSON: Yeah, sure.

MR. TORRIBIO: Good afternoon, I'm Gerry Torribio with Southern California Edison, and I just had a couple of questions to understand the report. The key thing is the wholesale access options?

MR. PRICE: Yes.

MR. TORRIBIO: You described it as as available wholesale sale to the utility. And I kind of understand that because in the past I worked with some of those as available QF contracts that were discussed this morning.

On the other hand, to explain it you've also said it's kind of like net metering but it's at the wholesale rate, and I know in the body of the report there's a comment that there's a precedent for doing this because we now do net metering on solar.

And I just want to be clear that the net energy metering tariffs that we're doing now on solar have several features, but one of them is there's a banking feature where the -- are we just talking about metering it when it exports and then buying it?

MR. PRICE: That's right.

MR. TORRIBIO: Okay, thanks.

MR. PRICE: And some of the confusion between the, we were really spanning a whole big range of size here from the really little ones to really big, right. So, because of that it's a little general, but the idea is as available energy sales at the market price when the energy is exported.

MR. TORRIBIO: Just two more quick ones. The societal benefit that was shown, I particularly remember the graphic that shows higher and higher levels of net society benefit at higher levels of penetration.

Is that net of the cost of whatever subsidies or incentives?

MR. PRICE: Right.

MR. TORRIBIO: Okay. And then finally, that idea near the end, the portfolio standard, where there's a variable incentive, would that be based -- more or less the project developer would open their books and --.

MR. PRICE: Yeah, there's a lot of implementation details on the portfolio standard --

MR. TORRIBIO: I don't want to go there --.

MR. PRICE: I haven't gone through every one of those, for sure.

MR. TORRIBIO: All right. Thank you.

MR. BRENT: Richard Brent, Solar Turbines. Hi, Snu, thanks for your work. Slide number ten? Thank you, one of the more challenging ones.

Policy comment first. If the utilities are not break even or made whole by any of this, this is going to be tough sledding, no matter what kind of incentives the Commission recommends to the PUC.

A couple of questions here, maybe clarifying. You say here "a total utility operating margin loss", and I need more clarification on what that means.

MR. PRICE: Okay. The way that the rates are set for the utilities now is based on their embedded costs and service, right. So they've got all kinds of costs in there, including those that are fixed and don't change with your CHP installation, and those that are variable.

So if you redo the bill savings to a customer, it has to do with a full embedded, they're saving a full embedded retail rate when they produce and use energy onsite, so the utility has lost the embedded costs.

But the savings on the other side are just the variable pieces that went down, the fewer wholesale energy purchases that they need to make. And so that net creates an operating margin loss.

Now, we all know that utility rates are set to hit a target rate of return, so these additional costs from the embedded rate are in part to hit that and in part to, how best to describe this, so just because there's operating margin between the variable cost and the embedded cost doesn't mean that the utility is making an excess profit.

The profits are already set, based on the rates going in.

MR. BRENT: And if I understand it, in this state we've de-coupled the volumetric flow of electrons from their operating profitability of the utilities? I could use some help?

Okay, I just wanted to make sure I understood that. The other thing that concerned me, and I don't know if it's here is could you address growth relative to this chart, growth of demand and supply and growth of the deliverability infrastructure in this state relative to that chart?

MR. PRICE: So, what we're looking at in this chart is the total cumulative penetration through 2020. So the growth of our loads in the state affect this chart in a couple ways.

The first is through the technical potential of the opportunities for CHP I think can show how the markets in different sectors are expected to grow, which will create more CHP opportunities. More CHP opportunities, from the technical potential, translate into greater economic potential. And so the costs and benefits of penetration of that growth in the market will be reflected in these.

MR. BRENT: So if we grow by two percent a year in our regional domestic product growth and our energy consumption grows at that rate, that's taken into consideration in that chart?

MR. PRICE: Right.

MR. BRENT: Thank you. Last one if I may. On slide 24 you mention the word incentive. It rolls out throughout. Is it fair to assume that incentives are more than just monetary?

MR. PRICE: Oh, yeah, yeah.

MR. BRENT: And is that what you mean by that --?

MR. PRICE: Well I think here we were talking about, in particular, monetary incentives. And I think -- that might have just answered your question?

MR. BRENT: You did. Thank you.

MR. DUGGAN: I'm Kevin Duggan with Capstone Solar Corporation, and that might have just answered my question also. Earlier today we saw some material from Nick Lenssen on the reasons why people might not want to install distributive generation, there were some seemingly non-economic reasons.

And there were things like it's just not our business to be in this business, and it's just not in our high level managements' minds to do this.

And I guess they do sound like non-economic reasons, but they probably can be changed in some ways into economic reasons. So the question is, within your model, are there things that you can do that look at those factors which are reasons for, you know, 87 percent of people surveyed saying no thanks to DG?

MR. PRICE: Yeah, exactly. So we've looked at that, and the model that EEA has that's got the payback penetration curve, so that 30 percent of folks will adopt at a two year payback or what -- I forget the number.

But I think those are based on surveys, and those capture a lot of the sort of non-economics. So this has to be so good for me to do this, because it's getting me past a lot of these other issues.

And so I think our penetration analysis, and the penetration analysis that EEA did really does pick up a lot of those non-economic perspectives.

The model that just shows for one application, so this is my, like the 300 KW reciprocating engine, that just looks at costs and benefits and doesn't look at well, you know, is that my core business or -- it doesn't take into account those intangible --.

MR. DUGGAN: A followup question then. If the host site does not find a payback of two years or so acceptable, can you analyze in any way a situation where you can find a third party -- and I think this was discussed this morning -- a third party, a ESCO or utility that has a different view of risks and a different ability to mange the risks, to take that on, and incorporate that into your model. And then what is the result?

MR. PRICE: Yeah, so what we did for a case like that, is the streamlining case. So what we did was everything that exists in the base case, we kept that. And then we just said we're going to do a number of policies that basically push out this payback tolerance.

So we're not going to make it as draconian as 50 percent in a six month payback, we're going to relax that a bit and see what happens. And then you can compute a new number of course.

Now the trick with that kind of analysis is well, how much are you really going to relax that issue. And it's hard, I think we accepted a year long payback and then re-computed the penetration. Something like that.

And it's difficult to know how far to move that curve for penetration study.

MR. DUGGAN: Thank you.

MS. LENNON: Hi, I'm Maureen Lennon, the Director of the California Cogeneration Council. I just have a few questions.

Going through the presentations this morning and this afternoon and the end user panel it just really struck me that we have to keep in mind the differences between the issues and challenges and problems of penetration and retention for the large users that we're talking about.

CCC represents almost 3,000 megawatts of the 25 megawatt and above larger projects existing in California. And the smaller ones, which we also value. But they're really different issues, as came out when Michael was speaking this morning.

In looking at the societal benefits in your assessment, the stakeholder perspectives particularly, looked at how complicated it is and how much controversy there would probably be.

Wherever you had a medium for the utility response I was thinking that was very kind to them, and it probably might be more negative than that when push comes to shove.

But, as Michael Alcantar was speaking this morning, if we do all these things, let's say we could wave a magic wand and do everything to get maybe 2,000 megawatts in a long distance time, we've got to do what we can to retain the existing great core that we already have in the state, and so without a lot of -- in order to facilitate access to the market you're calling it, and we call it long-term contracts with the utilities, a way to get the power to the utilities with the contracts' expiring.

So that's one point that, we don't want to lose sight of just how important it is to retain the existing generation and to facilitate it going forward, the CHP that's in the state.

And the societal benefit that I think is missing there, we filed comments yesterday, and I think people have it in the record. The reason people went into CHP in the first place the last time around was for the natural gas savings, the overall energy resource savings from natural gas.

You get to combine what would otherwise take more natural gas to do separately. And in Tom's comments he points out that the cogeneration that's existing in the state now, we are probably using 20 to 40 percent less natural gas than if we were doing separate thermal and electric energy generation at the same time, which is 192 million MBTU annually, which is about the equivalent of 3,400 megawatts of electric generation.

I mean, we are saving natural gas and conserving natural gas. So the reason CCC was very excited about your project and what Commissioners Geesman and Boyd are doing today is that this natural gas conservation is a primary state policy.

We can defer LNG, it reduces the cost to everyone if we continue to use less. And I just didn't actually see the societal benefit of the reduced natural gas use, which I think is a major societal benefit for everybody in California. Somehow I don't see that quantified in this analysis, or is it, and I don't --?

MR. PRICE: Well, to answer your question, I think we definitely have the natural gas savings quantified in terms of dollars and the societal benefits. If I can pull up one of my, just to show you how that works -- and it's not as explicit as you've got here. Let me get my --.

The reason you can get benefits for gas is, basically the credit you get is the difference between the wholesale, the price of producing power.

So, as a benefit you've got the wholesale electricity that you're valued, at the cost of electricity, which is going to be our embedded generation stock and their efficiencies at the central station plant, and how much gas it takes you to produce that same electricity with your cogen plant.

And since you've got a higher efficiency, the difference between the costs in terms of your wholesale electricity that you're avoiding and the cost of production, that gap right there is giving you this societal benefit of more efficient generation.

So, in terms of dollars, that's how that flows through to our model.

MS. LENNON: All right. I'm going to defer to Tom on sort of, I think there's an incremental societal benefit from the natural gas piece that's lost in that particular calculation.

COMMISSIONER GEESMAN: If I could just follow up on that, Maureen, I think in our 2003 IEPR our staff, I believe it was our gas staff, modeled a scenario which attempted to simulate the accelerated RPS goals.

And attributed to that greater penetration in renewals a certain volume of natural gas savings. And then concluded from that volume of natural gas savings that the market price for natural gas in California would be a certain amount less than it would be otherwise.

I believe that's the type of methodology that you're referring to.

MS. LENNON: Exactly. And I think for here, the CHP that exists now, because over at the PUC they're rightfully looking at rates, they're looking at setting avoided costs and capacity payments and implementing PURPA and doing that piece from the electricity perspective, that's what their charge is.

But really making sure that the priority for CHP is there for these broader state benefits needs to fall into the IEPR and the EAP2 and our agenda, so that's why we really would like you to provide the guidance on that side.

COMMISSIONER GEESMAN: I think that's something we'll take up with our staff.

MR. BEACH: Tom Beach for CCC. Just a quick followup on what Maureen said. On your societal benefits, did you use your avoided cost model that you developed for energy efficiency?

MR. PRICE: No, we didn't use that model, not because it doesn't apply to this but just because it's just too much to do all these different technologies and all this training. So this is basically a very simplified version of that.

MR. BEACH: So, the societal benefits, they're principally air emissions, CO2, NOX, particulates?

MR. PRICE: Just CO2.

MR. BEACH: Just CO2.

MR. PRICE: But you could add NOW or particulates, just our analysis saw a small number for those, I mean, you almost can't see a CO2 number as it is, and that's the biggest in terms of dollars, so --.

MR. BEACH: And is there avoided T&D in those societal benefits?

MR. PRICE: There is if you've got a T&D case. And in a T&D case what we've modeled is a contract which the utility has to make sure that the generation is operating, and then can therefore do some deferral, and then therefore there is a value of the T&D capacity and it comes back. But in the base case we don't have that as a benefit.

MR. BEACH: And just to amplify on what Maureen and Commissioner Geesman were talking about, I know that in your model for what it costs for energy efficiency programs you had a price elasticity term, a benefit where if you reduce the demand for electricity you reduce the price and that benefits all electric consumers who have to purchase out of the wholesale market.

And what we're talking about here is,

you know, CHP reduces the demand for natural gas. It's going to reduce the level of price in the gas market, and that has a price elasticity benefit across the entire market.

I know that LBL just did a study of this where they looked at energy efficiency and renewable technologies, how they reduce natural gas demand and what the price elasticity benefits to that are on the gas side, and we certainly think those kind of benefits apply for CHP as well.

MR. PRICE: And as you said, we've got those types of benefits in the avoided costs that E3 did for the efficiency program. And for this analysis what we have are staff assumptions, market price of natural gas forecasts, and it's the same in every case.

And corresponding forecasts of wholesale electricity prices. And so those don't show up in here.

MR. BEACH: All right. Thank you.

MR. O'CONNOR: Good afternoon. It's Todd O'Connor for the DOECHP initiative. I have three quick points I'd like to make.

If you go to your side for the carbon

fuel cell base case. If it gets to the point about making qualified heat recovery renewable. Since fuel cells qualify in California for renewable, under the RPS, have you factored in those benefits into this slide?

MR. PRICE: Which benefits, we've got the value of CO2.

MR. O'CONNOR: Right.

MR. PRICE: Of course we've got the SGIP incentive.

MR. O'CONNOR: That's separate from the ability of the utility to count any purchases of power from the fuel cell towards its renewable portfolio obligation. Have you --

MR. PRICE: So, the classification for renewables, I understand that, but I'm not --

MR. O'CONNOR: But did you facto that in to this slide or to the --

MR. PRICE: You mean some credit for getting towards the RPS?

MR. O'CONNOR: Right, any credit the utility would get towards its RPS obligations.

MR. PRICE: No.

MR. O'CONNOR: And it gets to the NOX question that was raised before. You had asked for several ideas for workshops. Maybe one would be NOX. And I think it would follow up on what Professor Bauer's going to talk about on his analysis, the work they've done on the south coast. I think that would tie very nicely into bringing in the NOX question.

And also, another idea would be to do a study of a workshop on what currently qualifies under the RPS that are CHP technologies, and follow that up on what would qualify if you are able to have qualified heat recovery qualify on the RPS.

That's currently going on in Nevada and Pennsylvania. And the reason I bring that up is the benefits that you've highlighted on slide 10, or the analysis rather on slide 10, probably would change considerably to the benefit of the utility and also tentatively to its customers and ratepayers.

MR. PRICE: Okay, we didn't do a specific look on how this would integrate with the Renewable Portfolio Standards. And there's a lot of complexity to that issue with the market price referent and how much the utilities have to pay --.

MR. O'CONNOR: That's right.

MR. PRICE: If the market price referent equals the market price, and that's the incentive they're getting say through a market access, then I think it should all net out so that basically it shifts where the utility is purchasing their renewables, but I'm not sure it shifts the costs up or down.

MR. O'CONNOR: But if you're able to come in with a baseload, at a market price that's less than the market price referent, then there's a greater benefit to the utility.

MR. PRICE: Right.

MR. O'CONNOR: Okay.

MS. TURNBULL: Jane Turnbull, League of Women Voters. I was pleased that Mr. Brent mentioned the fact that electrons no longer are a requirement in terms of procurement at point in time. And the League actively supports conservation as the first order of business in the loading order of procurement.

And we see CHP as a really important contributor toward that end. I guess one of my, or my main point is, now that the PUC is actually doing a procurement process of conservation, and the utilities are being reimbursed for that playing a very important role in that, should not CHP be part of that portfolio?

MR. PRICE: Yeah, that's definitely an idea to consider.

MR. VELASQUEZ: Joe Velasquez from Southern California Gas. I have a short question and then a longer question.

The first question should be fairly easy. For your central plant comparison, what was the heat rate that you were using?

MR. PRICE: We used the, I believe we used the CEC staff number from the white paper two years ago. If my memory serves, I believe it's combined cycle 7293.

MR. VELASQUEZ: Okay, great, thanks. And have you had a chance to -- I know you have a costs and benefits analysis here -- the costs benefits framework that was prepared in DGAIR by Ltron. Have you had a chance to compare yours and that one to see if there are any differences?

MR. PRICE: No.

MR. VELASQUEZ: Okay, thank you.

MR. PRICE: A short answer to the long question.

MR. RAWSON: One more, and then --.

MR. BEST: Thank you. Kevin Best with RealEnergy. Pacific Gas and Electric has now co-invested with us in 100 DG plants located in their substations using our waste heat to generate hydrogen. And we fill over 8,000 cars per day.

And, oh, I'm sorry, this is from a future presentation.

(laughter)

I have a quick question, Snu. Slide ten. We heard this morning that the megawatt number includes some credit for thermal. Do these numbers include some thermal credit or is this pure electric?

MR. PRICE: This is thermal too.

MR. BEST: This includes that 18 to 20 percent of --

MR. PRICE: Let's see, like, for example, for this example, and this is admittedly covering a lot of waste heat, huge, this, the value of waste heat is this section of it and then this section is the wholesale energy.

So that's looking like a lot, but then if we change the technology then --

MR. BEST: So that is relating back into

the kilowatt credit?

MR. PRICE: That's relating to the societal benefit that we just saw, as well as -- so, the kilowatts ar just the kilowatts installed as CHP.

MR. BEST: So it's just electric, all right. so there's no credit for the thermally offset electric from, say, chiller electric production, in those numbers. So if I see a eight gigawatt number, and I'm thinking about chiller offsets, I could think about a ten gigawatt number, or nine and a half or something like that?

MR. PRICE: Right. So you could, it's in the dollar signs over here, but this is just the megawatts in terms of CHP.

MR. BEST: Okay, in the dollar signs. Okay, thank you.

MR. RAWSON: Great. Thank you, Snu. I think that deserves a round of applause.

(applause)

If it's okay with the Commissioners we'd like to take maybe a 15 minute break. And we're going to do the utility panel next. So if the participants in that panel could come back just a few minutes early and get seated at the table,

we'll get started promptly at 30 after.
(break)

MR. TOMASHEVSKY: This next panel discussion is an opportunity for the investor-owned utilities to respond to some of the scenario analysis that you've just heard in response to the report in total.

But we don't want to restrict it just to that narrow topic area, since most of the utilities have been relatively quiet through the discussion. So any comments related to the end user discussion that you've had or just anything that's -- and the international experience -- we'd like to get some input as well.

So we'd like to use this time to focus on those two things, and take probably five to ten minutes doing that. One other thing, just to note as we've had a lot of discussion today has focused on what Snuller will show you the negative category of operating margin loss, and a lot of the QF discussion we had earlier, I just want to remind folks that the cost benefit analysis and some of that price related debate is still going to be part of PUC"s proceeding both at the DGOAR and also in the avoided costs proceedings.

So what you see in the list of negatives is not inconsistent with what the testimony that utilities have filed has suggested.

And in thinking through that, there's certainly things that can change those negatives, those numbers, either making them more negative or less negative, depending on what rate structures and tariff provisions and other things that are beyond the purview of our work here, although we're certainly interested in hearing those perspectives because we think it gives us a much more well-rounded perspective of the issues themselves.

We've got one representative from each of the three IOU's. On the far side is Joe Velasquez, who is a Commercial Industrial Markets Manager with Sempra, so he is representing both SoCal Gas and SDG&E.

To his right is Dan Tunnicliff, the Project Manager in the Business Customer Division. We've tortured Dan through a number of proceedings, so we thought it would be useful to do it yet one more time. So, thank you, Dan.

And then finally, Susan Buller, Senior Regulatory Analyst, who has been engaged in this discussion, although she has suggested that the person who was supposed to come here is now busy with other things. So thank you for stepping in and dealing with that.

So with that, let me turn it over to Joe, and we can continue our discussion. Joe did provide a presentation, not to the detriment of the other two representatives. We didn't ask for one, so the fact that Joe provided one we're going to let him go first, and say thanks.

MR. VELASQUEZ: Well, it's a very short presentation. This should take about seven minutes.

I'd like to thank the Commissioners and staff for inviting us to share our experiences with CHP. We have a long history in Southern California Gas, which is my main area of responsibility and experience.

I have supervised the self-generation incentive program in SDG&E from 2001 to 2004, and the SGIP program at SoCal Gas was my responsibility as well.

SoCal Gas and SDG&E support CHP. We think it's a very cost-effective way of generating electricity. It has great potential, and I just wanted o tell you a little bit of our current role.

Right now Southern California Gas Company is the administrator of the program in our service territory. We have an annual budget of about $17 million. SDG&E is not an administrator, so a lot of the responsibility in that area falls to the San Diego regional office.

As an administrator of the program, though, SoCal Gas has had a greater opportunity to involve itself in CHP. We support the technology in various ways.

One of the ways that we do it is we have a group of very specialized and expert account executives that know about the technology, that shepherds customers through the installation, economics, process of bringing in CHP, the permitting, all the way through.

Because we believe that it's very important to have the correct information in the customers' hands.

Since the beginning of the self-generation incentive program there's been 28 megawatts of CHP installed under the program in Southern California Gas service territory and seven megawatts in SDG&E service territory.

SoCal Gas is also proud that CHP makes up a large percentage of the program. We represent only 13 percent of the SGIP statewide budget, but represent 38 percent of the CHP megawatts installed statewide, so our percentage is quite large.

As you know, in SDG&E service territory we don't administer the program; however, SDG&E receives no funding for the program currently. They have invested their own funds in doing several things. We do have a project manager that works with the San Diego regional office and provides a single point of contact.

We've streamlined our interconnection applications process. You previously had to send your application to three different places, now you send it to a single point of contact.

We have updated our website, we have a link to the San Diego regional energy office and have information on distributive generation, and we've also sponsored trade shows, such as the Western Energy Engineering Congress, where distributive generation is a topic of discussion.

In the recently released fourth year

impact report on SGIP program it shows that 70 percent of the 99 megawatts that were installed at the end of 2004 came from CHP.

Now, while they represent 70 percent, they only represent 28 percent of the incentive budget. So ratepayers can look at that and see they're getting a much better deal from the CHP application than perhaps from other applications, just looking at that perspective.

In terms of availability, during 2004, the study also showed that the peak demand period, which was September 8 I believe between the hours of 3:00 and 4:00, the availability of CHP was 58 percent. That is, 58 percent of the incented megawatts were available during that period, as compared to solar where only 39 percent were available.

There ar some challenges -- so, those were the good news, here's some of the challenges. Some of the challenges of CHP is that, again, CHP has the potential to be cost-effective because, as we all said, it produces useful heat and generation at the same time.

The trick is to have those occur coincidentally at a specific customer's facility.

That's quite difficult to do, and I think that was one of the challenges of why we only saw 58 percent of the incented megawatts actually available during that peak period.

However, to be fair, the self generation incentive program provides no performance requirements. So there is no requirement to do it, you know, we just put it out there and we hope that it occurs.

So, one way to make it more effective is, of course, to plan some requirements on the capacity that's installed.

We also find that other results of the Ltron impact report disappointing. The study showed that only nine of the 29 CHP systems, that is about 31 percent, appeared to have actually achieved the 42,5 percent efficiency factor that is a requirement of the program pursuant to public utility code 218.5.

Although Ltron cautions that this is not a statistical sample, it does cause us some concern. And some of the problems were not only that the electrical generation or the non-electrical generation, the output, was below what was rated for the equipment, but also capturing and using the useful heat. There were operational problems and performance problems.

There are other areas we believe will be a challenge to CHP. These are high natural gas prices, which I think several of the players have talked about today.

There's high installation costs. Customers concerned with the system reliability and emissions. And we also agree with the CEC report that, at least in southern California it's going to be very difficult to meet the emissions standards in the next five years.

We believe that conservation and increasing natural gas supplies will be one way of normalizing some of the natural gas pricing, and investment in the technology so the applications are not only more cost-effective but more efficient to meet emissions requirements of clean burning, and also packaged properly.

So we believe that investment in that area, in RD&D, is necessary.

And the last slide, just to summarize, we believe in cost-effective DG. We also believe that our support must take into account the impact on other customers. We talked a little bit in the discussion before how the impact of other customers is there.

So unless these benefits can actually be proven and provided to customers we don't want additional incentives to really just end up as being higher waste, higher subsidies to our customers.

Among the various technologies we think CHP is the most promising in terms of cost-effectiveness, performance, first cost emissions as well as high natural gas prices will continue to be a challenge.

And SoCal Gas and SDG&E look forward to working with the CEC on further RD&D type of projects, and meeting some of those challenges. Thank you.

MR. TUNNICLIFF: Hi, I'm Dan Tunnicliff with Southern California Edison. Thank you for allowing us to participate this afternoon.

I work in our Business Customer Division and Customer Service Business Unit, so my division handles all of our business customers.

The points I'm going to be making, I'm going to be talking about what we've been observing from what our customers have done with regard to distributive generation and not necessarily focus on the Q app contracts and things like that that are currently underway, or dealing with, it's part of our portfolio.

But I wanted to just talk about what was in the report as far as observations of customers, customer choices if you will.

During the energy crisis, our high rates, our large business customers, commercial/industrial customers, carried a disproportionate share of the costs. Some of those customers had rate increases of more than 40 percent, making opportunities for them to defer some of those costs by putting in cogen or other technologies really made those projects much more economical.

Since about 2001 we've probably had about 150 projects installed. There's all sorts of DG-type projects for about 240 megawatts. In talking to our customers and knowing what choices they were making, you know these high rates coupled with distortions in rate design, meaning they were carrying a disproportionate share, the CNI customers were, made these projects much more economic.

Uncertainty in future rates, as was discussed earlier this morning about reliability concerns, having an outage for some of our manufacturers or semi-conductor developers, is catastrophic. So those decisions weighed into a lot of the choices our customers were making. All consistent with what we've been talking about today in the report.

Stand-by exemptions and state-sponsored incentives have also driven quite a few customer choices with regard to DG. The significant reductions that we've recently been seeing, relatively significant reductions compared to electric crisis prices, you know, creates more uncertainty as far as what is economic viability are for these projects going forward.

What our future rate design looks like, we go through general rate cases on a routine basis now getting some stability to what that electric rate is versus natural gas pricing is is going to be a key factor going forward for our customers.

Anecdotally, in 2003 and 2004 when we started resolving some of the high electric prices we started seeing more DG following whatever incentives. It makes sense, projects that are exempt from stand-by are more likely to go in anecdotally.

Most of those projects that went in, 2003 and 2004, in our service territory, were less than five megawatts, taking advantage of the self generation incentive program if available to them, etc.

I might be stating the obvious, and we're going to be talking quite a bit about this, but the report and the models that Snu put together definitely are a good starting point for some of the policy considerations, but there's yet many things that need to happen.

There's the input values that have yet to be determined. In a couple of weeks we're starting DGOIR hearings to develop a specific cost-benefit model for evaluating DG technologies, all DG including cogen.

That's going to be an important factor. We don't know what that yet looks like. The avoided costs proceeding is out there to develop some of those input values that go into this model. So, you know, even thought we saw a lot of analytics earlier today we don't necessarily know that that's ultimately what the analysts are going to play out to.

But again, focusing on the policy issues at least you have a starting point, so ultimately when you do have a model come out on what these avoided costs do look like, at least you have some options from a policy perspective of which way we want to take the state, or the Energy Commission wants to help pull the state along.

One thing that was talked about also in all the policy options, including the base case results and then losses to the utility. And meaning losses to the utility means the other ratepayers end up picking up most of that burden, that choose to not implement a DG option to serve their electrical needs.

And there's a couple of concerns we've had, and I'm glad Joe kicked it off with some of the results from the fourth year impact report. The third year impact report from back in the fall was even more dismal from a results perspective, about 90 percent of the projects failed from the minimum efficiency standards.

Once given the incentive there is no recourse for our customers, all of us, that are funding those projects, to get that money back. That's a problem, and something that needs to be evaluated we think going forward.

As far as how projects pan out from a policy perspective, there's some new input values that we'd be happy to work with Snu and others to talk about what the economics look like going forward.

On April 14th we had new rates go into effect for Edison service territory. We now have stand-by rates that are based on a settlement of many folks that are in this room, so hopefully it meets the requirements of some of our users.

New SGIP rules, we don't know how that's going to play out with regard to installation rates of projects. We have reduced incentive levels but larger projects can now start participating.

And other things that were mentioned also, resource adequacy requirements and the possibility of including distributive generation to deal with resource adequacy requirements. A lot of work is I believe yet to be determined and yet to be done on how do we even calculate and contemplate using a customer site option to satisfy resource adequacy requirements.

One things we've raised in a couple of other forums, you know ,what's important for input values, the state needs to decide and determine what level of information is really needed, and evaluation is really needed, for these technologies.

You look at spot checking the SGIP, and anywhere from 70 to 90 percent of those projects fail, even though on paper and penciled out they look great, it asks us to, it begs the question do these facilities really perform as stated?

Granted, that's a very small percentage of the interest for overall CHP in this state, but it is still an important factor and needs to be looked at.

One of the other points that was raised in talking, a lot of discussion was based on gas prices and fluctuation of gas prices. And what we have seen -- I don't have specific numbers -- but when the cost of gas goes too high and it's more economic for a customer to shut off his or her cogen, they will.

And ultimately the utility has to provide the service there. Does that necessarily give us the service we need to continue down and provide electricity for all our customers. So --.

A couple of other points. I think a lot of points are going to be made tomorrow regarding distribution system planning, but the utilities are required to look at DG as a solution versus a traditional wire solution and we've been participating in EPRI and E2I and some folks in this room -- I think Solar Turbines is part of our pilot project -- to look at how do we best utilize or look at planning or doing distribution system planning using the DG option. I think we'll talk more about that tomorrow.

Also Capstone Turbine and Ingersoll-Rand and forgive me if I'm not acknowledging others, because a lot of folks have been helping us out, trying to figure out how to best make that happen.

And I think I could continue on, but I think we'd be overlapping a lot of the points that we wanted to talk about today, so I'll turn it over to Susan.

MS. BULLER: Hi, my name is Susan Buller. First of all I'd like to thank the Commissioners and the staff and the members of the audience for what so far today has been a very intellectually challenging and productive and articulate and passionate presentation of a very, very difficult subject.

And I'm going to now tell you what the difficulties are from PG&E's point of view, of course, which is going to be slightly different from yours, and I hope slightly enough different from everything you've heard from the two gentlemen to my left, and I hope i won't bore you to tears when I mention for the third time this has an effect on other customers.

To start with, PG&E supports customer choice, especially in the area of distributive generation, as a way for them to meet their energy needs, we have for needs.

I believe that it would be hard for anyone to challenge the statement that I'm about to make, but I actually don't have the facts to base it on, but I'll take any bet in the room that PG&E has more distributive generation than any other utility in the United States. I think that's a true statement and it's been true for years. I know it's true about Salton.

Second point. We believe that distributive generation, especially renewables and especially combined heat and power can make a very big contribution to the state of California's addressing of its energy future over the next five to ten to fifteen to twenty years.

And then the third thing I want to put out here for your consideration. First of all, you have PG&E support, secondly we had there's a role for DG; thirdly -- this will come as a surprise to no one in this room -- rates are high in California. Energy's expensive for all of our customers.

So that sort of structure that we're trying to play through what the right approach for incorporating distributive generation into the energy future of California is.

This is what PG&E thinks any policy developed around combined heat and power or any distributive generation needs to have. The policy needs to include benefit cost analysis.

And the two from our perspective, although there are various ways and may cost and benefit analysis you could do and depending on what you're trying to do some may be better than others, but the two most important ones are the TRC test, the total resource test, that's the societal test. That sort of, the state of California gets to ask the question is this is even a good idea.

And then the second most important one from PG&E's perspective and from our customers perspective is the point of view of the non-participating customer.

This is the customer that, if you're designing a program that affects rates, this is the customer that's going to pay for that program. So you need to ask whether they're getting anything out of it, and how much they're getting out of it.

Those two tests are paramount when you're designing whatever distributive generation or CHP policy you're going to have.

And to no one's surprise, probably the best description of those two tests can be found in testimony recently filed in the DGOIR by Pacific Gas and Electric Company. And I urge the Commission and the members of the audience to read that testimony. I'm not the witness.

First of all, you need to do your benefit cost analysis on why you're doing this. The second thing that you need to do is take into account the bigger picture. The only thing that you're going to do tomorrow is not DG yes or no, CHP yes or no, solar yes or no, that's not the only thing you're going to do tomorrow.

You have other things you might do with the customer dollar, and you're combined heat and power policy needs to be developed in that arena that takes into account other things one might do.

The third thing you need to incorporate is the procurement process. This is to me a choice about needing energy. So it needs to be integrated into the current process. How well does this choice, along with other choices, meet the least cost best fit criteria that the procurement process calls for.

How well does this choice match the next short that is going to be needed?

The third thing that you need to do is include all of the options that are available to you. And this is something I was glad that Snu mentioned, the idea of market transformation. And you had that slide that sort of models market transformation.

Because there ar two things that have come up repeatedly today from a variety of speakers that are very on point about market transformation and have very little to do with increased incentives, except to the extent, and I'm going to quote you on this, "you have to make it so good that even I'll do it."

That's the one way that an incentive can affect what really should be accomplished through possibly other means. And the two things that have really come up all day long are this, you know, if it doesn't pay back in at least two years less than half the people are interested in doing it.

That is a huge market barrier. You're talking about people who are unwilling to take a step with a 50 percent rate of return. I mean, good grief, you're giving me stuff like that, I'll buy it in a minute, I'll borrow money to buy that.

So the first problem is that's an education problem. That is not the rebates aren't high enough, the benefit isn't cost-effective, that's an education problem.

And I think we had an excellent example this morning from Ralph about how you overcome that. And that's to present it not so much as we need to get the payback period shorter as to change the question and say can I pay for this out of my current energy budget.

And when the answer to that is yes, when you have a rate of return that's 50 percent, then you can start making a decision that's make some real rational sense.

Okay, I saw somebody shaking their head. And then we get to the second thing, and the second thing is this isn't my core business. I do XYZ. In your case it was silicon manufacturing, in somebody else's case it's food processing, in somebody else's case it's oil refining. But what it's not is generating electricity.

So that's the other big issue that I've seen today. There's the payback period and there's the fact that this is not our core business.

And one of those can be addressed by education, and the other one can be addressed I think by a combination of education and identifying an expertise or methodology to get something where it needs to be that's something besides just (inaudible).

And that's the direction that I invite the Commission and people that are supporting this to suggest that we move, because I think that there can be a lot more market penetration by doing some real market analysis and some real market barrier research, and then direct our policies towards something that will move the market more effectively rather than just saying let's put more money there.

And then there's one more. It's the final one and this isn't that major a point. But as we're developing state policy we need to remember that this is a state policy, and we have three representatives of the IOU's up here, but whatever the California Energy Commission is going to recommend needs to apply to the entire state and I would suggest that we need to look at ways to incorporate utilities as well, because they represent almost a third of the energy in the state of California. The end.

COMMISSIONER GEESMAN: I'm not sure I had a question, I did want to commend you though, each of you actually, for the graciousness of your remarks.

And I think PG&E had some points that we need to ponder pretty carefully. Having said that -- well, I think each of the three of you confront the same situation that Commissioner Boyd and I do, and that is that everybody appears to be in favor of combined heat and power.

Over the course of the day you've trained me to use the current term, combined heat and power, or distributive generation. And we have close to two and a half decades now of rhetoric stacked on top of itself as testimony to how much we're in favor of this.

But the facts are that for the last 15 years or so we've not really added much capacity in this regard. We've spent a fair amount of money on incentives or created a fair amount of policy effort toward incentive programs, but in a circumstance where we have been wildly inaccurate about our projections of fuel costs and where the status quo -- the regulatory status quo, the financial accounting status quo -- makes us increasingly more fuel dependent in our natural gas system, I wonder what the three companies' ideas are for how we would increase penetration of these technologies.

And assume that the regulators are prepared to say yes, the ratepayers are going to have to pay for this because the regulators have determined it's the right thing to do.

MS. BULLER: Well, the first, my first response to that is to reiterate my closing remarks that, if what we're trying to do is get market penetration, then what we should start with is an analysis of the market and the drivers that are preventing that penetration.

And once you've identified the drivers you may find that there are much more effective solutions than simply increasing rates or, you know, you might find a change in the rate structure itself could make a difference.

You might find that an educational program might make a difference. You might find that some assistance on the technical side might make a much bigger difference than just increasing the incentive.

COMMISSIONER GEESMAN: I think you're probably right on the incentive side, but I suspect that what you'll come up with, or what we'll come up with is something that each of you in future months or future years will criticize as excessively command and control directives pointed at your companies.

Portfolio requirements, net metering

requirements or the functional equivalent thereof --

MS. BULLER: I don't think I was suggesting either one of those.

(laughter)

COMMISSIONER GEESMAN: But I'm suggesting to you that, in the absence of more constructive or more detailed recommendations beyond simply run faster tackle harder, that's the direction that I think inexorably the state is likely to be headed.

MR. VELASQUEZ: Commissioner, I think another area that needs to be looked at, PG&E talked about education, but another thing is how do these technologies perform out in the field.

I think Mr. Renne discussed this morning about the economics of a project that extended significantly because of additional costs because things didn't work out as planned.

We've seen in the results of our own projects, where we've invested significant amounts of money, and the state has, in this self generation incentive program, where projects need to be planned, engineered, designed, to work in one way, to only have them operate completely differently.

And the results are there.

COMMISSIONER GEESMAN: What i I cherry pick and focus on the larger size end of the spectrum, would you make the same conclusions?

MR. VELASQUEZ: I imagine the larger user is more sophisticated, they can look at that, it's a much more dollars involved, probably better decisionmaking takes place there.

COMMISSIONER GEESMAN: If I'm interested in installed megawatts isn't that where I want to go?

MR. VELASQUEZ: Probably with the larger units.

COMMISSIONER GEESMAN: And I don't think educational programs or public service announcements or other non-big stick policies are likely to increase penetration at that large end of the spectrum.

I think that where we are headed, in the absence of somebody coming up with something better, is directives from the state that we need to change some of the fundamental ways in which our regulatory system works.

And I realize that puts the honus on the regulatees, and the regulators have to be willing to pass those costs through to the customers. But I think that's the direction that things are headed in the absence of better suggestions.

COMMISSIONER BOYD: Well, let me take a kinder, gentler side approach here. Mr. Geesman and I always play these roles, good cop bad cop.

One, I don't disagree with anything Commissioner Geesman said, but let me go to the four points made by the PG&E representative. As I wrote them down well, I can certainly agree with two of them, state policy, all-inclusive.

I think these two Commissioners, and perhaps the whole Commission, is for a lot of all-inclusiveness in the state policy. We're considering things not in only this area. So I check that off, okay.

Education is always helpful and good in certain arenas.

But then we've got the cost benefits of least cost best fit, and that's very criteria-driven. And historically lots of things fail in that arena. And it's easy to fail at things when we look at them in the very conventional sense.

But I'm just wondering if this isn't the kinder, gentler way by making this more positive by finding more benefits, or finding those benefits that aren't being properly accounted, to make cost benefit look a little more positive or least cost best fit criteria work a little better.

I continue to wonder if the benefits of keeping certain industries functioning during a, God forbid, blackout or something, isn't a very positive benefit to the economy of the state.

And thus if we had people involved in self-gen or cogen or CC, it's you know, chilling, heating, cooling process, we couldn't keep certain industries, maybe energy industries going, while we work our way out of our problems.

There's benefits to some of those things that I don't think we take into account. And unfortunately in a post-9/11 world we live in there's a new benefit that we have to add to this idea of security, besides just talking about energy security through energy diversity.

So, during the depths of the crisis, the thought of getting more refineries to cogen, if I might, was seen as a way to get megawatts, was seen as a way of getting megawatts from people who had money when nobody else did at the moment, and was beginning to look like a way to address energy security issues, because we discovered that if the lights go out and pumps go out and the gasoline doesn't flow the transportation system shuts down and all hell breaks loose.

So maybe we need to look at other benefits to make this look a little more positive than it has in the past.

And of course we hear repeatedly, and God knows I've heard it repeatedly, the cost and fees we put up in front of some of these things become a problem, and that's an adjunct to the whole idea of cost and benefits, and you're right, I guess, the regulators need to look at this and work with other regulators to try to asses the pluses and minuses.

So I think after these two days go by we're going to have a bushel basket of ideas, but I'm not sure we're going to actually be able to encompass all the problems in these two days of hearings and we'll probably have to figure out how to touch on some more of them.

But this was a question that turned out to be a statement, but at this point in time it's just kind of a reflection on things as I see it.

Anyway --.

MR. TUNNICLIFF: One of the things that I think we all hope to get resolved in the next several months, and hopefully it won't take several months, but as the DGOAR and the cost/benefit analysis is undertaken at the CPUC, and I think there has been quite a bit of effort put into that, a lot of joint agency participation.

And the California Energy Commission has definitely had a good role working with the ALJ and the Commission on that. Hopefully we'll get a clearer picture on what costs and benefits are, when do we have to make those policy decisions, when the overall arching benefit outweighs that cost, those are the things that we hope to get out of that.

The utilities need direction just like all of our participants here need direction. And hopefully that will be a good forum to resolve some of those issues and work with others in this room.

There's a lot of good ideas out there, we just need to have a little bit more of a roadmap as far as how do we quantify all of those inputs.

MR. TOMASHEVSKY: Just following up on what Commissioner Boyd said, when you step back and look at it in the context of this IEPR process, we established a loading order concept really with the '03 report.

What we're doing is refining it, and I think this becomes a major input to try and determine where cogeneration fits in the grand scope of that. So we're definitely in the information gathering mode, so the more the better.

And actually, before I forget to say it at the end, I think, in terms of comments that are due on May 6th, one thing that would be useful goes back to the discussion we had earlier in terms of how the ISO transmission rate structure seems more problematic than maybe we have looked at before.

And so to the extent that there are comments you want to file that explain what some of those problems are, I think that would be really useful. Because we don't necessarily focus on that aspect of things. The transmission rate pass-through to the utilities, we tend to somewhat ignore that. So I think it's time to bring us up the learning curve on that, on that particular issue.

Any other comments from the dais? Any comments from the audience?

MR. ALCANTAR: Thank you. Michael Alcantar. I have some questions for PG&E and for Southern California Edison.

I'd like to start with Edison. Thank you for your set of comments about the long list of questions that you feel need to be determined, we have to go through a couple of proceedings and we have to come back here and study and we have to come back and analyze and we have, there's a lot of talking to do and not much doing.

What is your solution for those combined heat and power facilities who are coming to the end of their contracts, who are coming to a position to where they have to make decisions whether they're going to install boilers as opposed to maintaining their cogeneration -- and some of these are with three year lead times to do them I might add.

Is one solution that you would agree to or accept is that perhaps Edison should issue an

RFO that actually would make these QF's eligible for the RFO? Which hasn't happened yet.

MR. TUNNICLIFF: I hate to defer this question, but I'm going to have to defer this question. I don't represent that part of the company that handles qualifying in pursuit of contracts. I apologize for that.

But possibly we can respond to your question by written comments if we can get some additional inputs there.

MR. ALCANTAR: When you're looking at responding then -- and I hear you appropriately bypassing a question that you're not prepared for -- would you also consider whether one option is while we are in regulatory uncertainty and while we are talking and not doing, perhaps the right thing to do is simply endorse and sustain existing contract pricing and terms until we can make the decision?

If we don't know what the future will be, maybe maintaining the status quo is a prudent practice for all of us.

Ms. Buller, before you leave, would you say you can agree or disagree with the following statement: There's no transparent and functioning day ahead electricity market in California today?

MS. BULLER: I don't think I even know enough to answer that question, so I'd have to decline.

MR. ALCANTAR: Okay, and just before I pass you over, Mr. Tunnicliff, would you agree or disagree with that statement?

MR. TUNNICLIFF: I can't respond to that either.

MR. ALCANTAR: Could you tell me who James -- I don't want to pronounce the name improperly, Schiehtl, is.

MR. TUNNICLIFF: Yeah, Jim Schiehtl, he works in our RP&A, our Regulatory Policy and Affairs organization.

MR. ALCANTAR: And his title is Manager of the Right Design Section, the Division of Regulatory Policy and Affairs Department, does that sound about right?

MR. TUNNICLIFF: I work with Jim periodically, and that could be his title.

MR. ALCANTAR: Would it surprise you that the statement "there is no transparent and functioning day ahead electricity market in California today" was submitted by this gentleman in sworn testimony before the California Public Utilities Commission on January 20th of this year?

MR. TUNNICLIFF: I'm not going to answer that question.

MR. ALCANTAR: Okay, I can understand why. Let's assume that, and I'll go back to PG&E, that the market that we're looking for, that's going to provide benefits for combined heat and power and incentives, doesn't exist, isn't functioning, isn't transparent, isn't real.

It's not one that you as PG&E would rely upon to secure your prices. Would that have an impact on your assessment on what this Commission should do with respect to the policies on combined heat and power, both existing and new?

MS. BULLER: I'm not sure I got your question right, but what I think you said was assuming that there was no market to provide pricing, would that affect the recommendations I make today to the Commission, as to how they should form policies about current or future --.

MR. ALCANTAR: I'm not sure I understand what you mean by pricing but --

MS. BULLER: It could take awhile to get this question worked out.

MR. ALCANTAR: If there is no
transparent and functioning day ahead electricity market in California today, and we are assuming I think as you have heard or I think you even responded to, some of the benefits that you think ought to be assessed are the wholesale power sales that would come from these varying units, combined heat and power units in the system, would that affect your recommendation if there was no market that was reliable?

MS. BULLER: Okay. I'm going to try again. If there's no market to provide a price signal, then does that change my recommendation that we need to do a benefit cost analysis as part of our decisionmaking process?

I don't think I'd change that -- but I can tell by the way you shook your head that that isn't what you're --.

MR. ALCANTAR: That's fine, let me move on.

MS. BULLER: I'm sorry about that, Mike, but --

MR. TOMASHEVSKY: How about one more, I've got about four behind you.

MR. ALCANTAR: I'll try this one. With

respect to the definition of losses of revenue, could you define that term for me as you think it applies to PG&E in your testimony today? What are you entitled to receive?

MS. BULLER: I don't think I used loss of revenue in my testimony today.

MR. ALCANTAR: Okay, I thought --

MS. BULLER: I referred you to the testimony that PG&E has filed in the DGOIR and I believe we have an exculpation note, the cost of benefits in that, but I'm not the witness for all benefit and cost analysis, so --.

MR. ALCANTAR: You did point out the concerns with the effect on other customers by combined heat and power. You did point out that there is a contribution associated with rates being higher for any expansion of combined heat and power programs.

MS. BULLER: To the extent that --

MR. ALCANTAR: Are you entitled to those revenues as some matter of right? You, PG&E, as opposed to the --

MS. BULLER: Um, PG&E has fixed costs as determined by the Commission that we're entitled to collect. And if they're based on sales, and if sales go down, then that amount of fixed costs that need to be picked up in rates by other customers will of necessity go up, upward pressure on rate.

Whether it would be collected to the penny, or whether part of it the shareholders will see in terms of reduced profit, that's going to play out the way it plays out. But just as a general rule, if sales go down and fixed costs remain the same, then the average cost for remaining customers is going to go up, there's an upward pressure on rates.

MR. ALCANTAR: So let me understand then. If I'm a combined heat and power customer I don't have the election that, say, PG&E has to go out and shop for a marketplace for natural gas or shop in a marketplace for electricity purchase, I'm a captive customer because I am obligated to provide you with a certain amount of revenue, is that a fair statement?

MS. BULLER: If you're taking service under a CPUC approved tariff from PG&E, that creates a legal obligation on your part to pay that.

MR. ALCANTAR: And let's assume that I

decide to build my own project and stop taking service, are you saying that shouldn't be permitted?

MS. BULLER: No, I'm not saying that at all, I don't think I said that.

MR. ALCANTAR: Thank you.

COMMISSIONER GEESMAN: Thank you Michael. Jeff?

MS. BULLER: Could I just clarify this a little bit?

MR. TOMASHEVSKY: Absolutely.

MS. BULLER: I'm sorry, I was put in a position where I was apparently saying that PG&E would or would not do something. And my testimony today has been directed to the kind of considerations that the California Energy Commission should take into account when they're setting energy policy.

I do not pretend to be standing here and saying that PG&E is or is not anything. On behalf of the customers that would receive this upward pressure on rate I'm asking the Commission to take certain things into account.

Thanks, Scott, appreciate that. Hi.

MR. BEST: Hi. Scott, could you please

key up the slide on CHP challenges in the SoCal Gas presentation? I just wanted to comment on PURPA.

We hear over and over -- and it's true by the way -- that 70 to 90 percent of these systems fail to achieve the efficiency target bogey set in 218.5 of 42 and a half percent.

This is not high math. The efficiency target is not 42 and a half percent. It's 42 and a half percent giving half credit for thermal. So, it's important, we spend hundreds of millions of dollars as a country and as an industry to squeak out a percent or two more out of these machines, so this is not insignificant.

If a machine today is 30 percent, and most cost-effective technologies today are 30 percentage-ish persistent, we're 12 and a half points away from the bogey, but we only get half credit for that.

We're 25 percent away from the bogey. So for me to generate electricity at 30 percent efficiency I have to generate thermal at 25 percent efficiency, okay, that's a 55 percent bogey.

Now, the utility, on the best days, half of that. So I just want to be clear. In the last 35 plants we've built, sub-one megawatt, we've missed that bogey pretty consistently, around 20 to 30 percent of our machines every month miss the bogey. It's not because the machines failed, it's because these facilities don't drink enough thermal.

For every kilowatt we produce we produce a kilowatt of thermal. How many customers in the state drink that much thermal, cooling or heating, or hydrogen?

So, I would say that this is not a failure of the plants, this is a failure of the users to suck up this thermal. So where'd the bogey come from? Well, it came from federal law, so the state picked it up.

We analyzed this very carefully, we believe there are PURPA police looking out at our machines. We curtail, we turn off the machine, until time goes by and thermal is used. And then we turn on the machines again.

So, it's very painful to shut the machine off for a bogey that's 200 percent our competitor. So, we do it every day, it's law.

I would also offer, we talked a lot

about larger machines. Well, I'd love to put in larger machines. But I can't do Costco's with my small machines. I can't do any box stores, I can't do shopping malls. Wesfield would love us to do all their malls, we've signed them, but we get to looking at the thermal and we can't do them. So we walk away from all shopping malls. I can't do this building, not enough thermal.

So I would argue that the bogey is perhaps a little high. and I would also say that, as we go to larger plants, you know, I'd love to put in a solar merc 50, but I've got to do something with the thermal. Who can use five megawatts, or even three or two megawatts of thermal.

So then we should start looking at, okay, microgrids, power parks, wherever there's a Costco there's a couple of hotels across the street -- oop, can't cross the street.

So, I would argue that the result of this extraordinary standard drives us to shut off our equipment, to walk away from most energy users.

So, Mr. Commissioner Geesman, I would love to penetrate, but I have to ignore most energy users. Thank you.

COMMISSIONER GEESMAN: That's a PURPA requirement, is it not?

MR. BEST: Well, it's PURPA, but we've adopted it as our bogey for the state, so most projects we underwrite we pick out right up front as a PURPA.

COMMISSIONER GEESMAN: But if you entered into a non-PURPA contract you wouldn't be constrained by the same bogey, would you?

MR. BEST: I wouldn't be eligible for stand-by exemptions or self-generation incentive plans. It's impossible, I can't put a machine out back here. It should be that simple, but --

COMMISSIONER GEESMAN: And how much of that then is under the control of the state?

MR. BEST: All.

MS. BULLER: All.

COMMISSIONER GEESMAN: If we departed from PURPA standards, could we not address that problem?

MR. BEST: Yeah, I'd do your Costco first, you bet. Thank you.

COMMISSIONER BOYD: So we do need to be in the nation/state of California.

(laughter.)

MR. WILTSEE: George Wiltsee with Ingersoll Rand. And I'd like to just comment on the point that Nick Lenssen led off with today, and the PG&E person talked about also, which is this issue if you have a two year payback on a cogen project only half of the potential hosts will go for that kind of a situation.

And a comment about education was made, but i think it's actually a slightly different issue. These folks are a lot more savvy than, just street smart I guess than that.

And I think what it is is risk. And they look at this two year payback that's being presented to them by a developer or a real energy -- although a real energy model doesn't do it that way, but -- they're going to own and operate it, and they ge a two year payback, and they ask the question well, what can go wrong here? Or what's the sensitivity analysis?

And, you know, what if the price of gas goes from X to Y? Or what if this machine only operates 50 percent of the time and it's being repaired all the time? Or things like that.

And so, I think that's an issue that has to be addressed by ourselves in the manufacturing of this equipment community, as well as the developers and installers.

But the question is what can we do from a policy development point of view that might address that? And I'm not sure I really know the answer, but one thing that comes to mind is when, for example, in the self-gen program toady we have currently the instruction that we're going to look at a phaseout of this incentive program over time.

And what should it be, how quickly should it happen. Snuller had a chart that kind of implied that it should start now and, you know, just straight line down.

And I think one answer is we need experience and time to develop the reliability and applicability of these technologies, and especially when you factor in that in a very short time we have to meet 2007 emission standards.

We're looking at, actually a new technology now. Kind of a new breakthrough in the performance level of this technology. So I think one thing we need to think about is to give these current incentive levels more time to bring in the projects and the experience to build a sound technology base for CHP.

MR. TOMASHEVSKY: Thank you, George.

MR. BRENT: Richard Brent. Question to the panelists. I heard distributed generation, DG, in probably more than I heard CHP. Could you help me understand -- I think Joe you had it on your slide -- CHP is part of DG.

If you see a difference between distributed generation and combined heat and power?

MR. VELASQUEZ: Well, I think that distributive generation right now is primarily, I'm looking at it from the self-generating incentive program, which is under my responsibility.

Which is, either CHP or cooling plus heating and power production. So it's mostly that. Cogeneration, I've been here long enough that I remember it as cogeneration.

MR. TUNNICLIFF: And in talking about distributive generation, or DG, as looking at or referring to the wide gamut of the technologies. And in meeting and working with and using different technologies that our business customers look at, they look at photovoltaics.

And some are looking at fuel cells, operating in a combined heat and power application, as well as internal combustion engine, fire, combined heat and power.

So, thinking of it generally and pretty broadly about what some of our customers have adopted or looked at, so, it's not necessarily focused on one particular technology.

MS. BULLER: I think for me combined heat and power is a subset of distributed generation. Distributed generation is just talking about customer type, and combined heat and power is a part of that. But I'm not an engineer, so I can't --

MR. BRENT: Neither am I, so that works. If I may, we're finding nationally sort of a split between distributed generation or distributed resources and combined heat and power.

Because the load factor for combined heat and power, generally speaking, is more of a base load. People can't afford a machine that's only going to run 500 hours a year.

What we're hearing from the utility industry across the United States, distributed resources could be storage as well as generation of supply, is put more at peak shave, and manage the grid and be used as a grid management tool.

So I want to make the distinction between distributed generation and what I suspect we may be talking about tomorrow, and base load combined heat and power, which may have a more onerous inference in that I'm talking five megawatts of capacity away from the utility by putting somebody into a base load CHP, where DG may very well be 200 hours a year, 300 hours a year, and would use that as a split.

I don't need confirmation of that as much as my experience in the last few years has shown me that kind of a difference.

The other point that I'd like to make is that if we go to Joe's first slide, I'd love to get 2,520 KW for our CHP systems, and would be willing to stand here and take anybody's order who can give it to us, when generally speaking our retail, and you can go from there, is probably somewhere between 800 and 1,000 dollars KW.

But I'm in a size class that's a little bit larger, and I need to qualify that you're talking about three megawatts and above. And it does have economies of scale.

The other point that I would point out, and I don't know which one it is in Joe's slides, and again just more for clarification, how much got installed -- we've enjoyed a good relationship with SoCal Gas.

SoCal Gas has even in fact shareholder approved rates that are encouraging people to use more base load gas. And you can talk to Joe afterwards about that, separate from SGIP.

We've had a more difficult time in SDG&E, and yet I believe we've even installed 20 megawatts in there that has not received any of the SGIP money, in the SDG&E's territory. And to another part of the slide, we have not had any problem getting our emissions permit and still meeting the cost effectiveness to the end user.

MR. VELASQUEZ: I should say that these were the numbers for the SGIP program, installed under the SGIP program.

And the other, the project costs, because I have seen also when I go to different DG forums, and I've been promoting DG for a long time and CHP, numbers in the 800 to 1,000 per kilowatt, 1,200.

And I was surprised, as you can see that all these that are required that go through our program and project cost, I'm looking at these and I'm seeing these numbers that are huge for project cost of installing. So this is based on actual data, systems installed. So I was quite frankly shocked myself to see some of these costs.

MR. BRENT: I'll be glad to take the order. Well, last point, before, with the $600,000 upset to your $3 million, that was for permitting? Or that was for technical?

MR. VELASQUEZ: It was for abatement equipment, for infrastructure and SCR's and --

MR. BRENT: Fair enough. Good clarification. Thank you very much.

MR. TOMASHEVSKY: Thank you, Richard. One more and then, because we won't want to overlap with tomorrow's workshop we'll move on to the next thing.

MR. DUGGAN: I'm Kevin Duggan with Capstone Turbines and we're taking orders too. (laughter.)

I wanted to amplify a comment by Commissioner Geesman, and then something perhaps shocking, and then ask a question.

The industry, distributed generation in

California, has had a lot of things made to go for it in the last few years, you know, we've gotten rid of stand-by charges for many installations, exit fees, combined line charges for many situations, we've got a significant incentive program in place, we've addressed interconnection standards.

We've got the utilities even supporting distributed generation. But the point you made, Commissioner Geesman, over the last five or fifteen years we've seen almost nothing really added to the stock of CHP in this state.

And so the question, and maybe the question is of course why is that, that we've seen nothing happen? We heard some statements from people in business saying it's just not their core business, they just don't want to do that, it's a low priority.

And I guess the thinking I've come to, and the shocking point I'd like to make now, about why business people can say that, is really because of the high quality of the product and service they get from the utility. The utility meets their requirements and CHP doesn't do the job as well.

And so the question that I then get to is how has it come about that the utility industry has been able to provide and meet the requirements of customers to a much greater ability than almost anyone else can, to meet the requirements of the vast majority of customers to a greater extent than anyone else has.

And I think a part of the answer to the question lies in the fact that the utilities have been a regulated monopoly for maybe as many of 100 years, and out of those regulations they've been able to establish a place and a presence.

In fact, the regulation themselves, the protection they get, the guaranteed rate of return, all these things, are known monetary incentives that have been created and established over a very, very long time that have enabled utilities to become dominant, powerful providers of a high quality service.

That makes it very, very difficult for anyone else to compete with. So I guess the question is, how do you react to that?

(laughter.)

COMMISSIONER GEESMAN: You can just take bows.

MR. TOMASHEVSKY: And that works really well, because you've been tortured so dramatically throughout the course of this panel we should at least leave it on a positive note.

Why don't we thank your three panelists for putting up with us.

(applause)

MR. RAWSON: Okay, I don't want to lose you yet, we're in the home stretch, hang in there.

Well, we've kind of gone the full gamut, talking about CHP and distributed generation today, and part of the Energy Commission's responsibilities is to be good stewards of the environmental issues as well.

So we wanted to end today's discussion talking about some research that the Energy Commission's PIER program has been funding with UC Irvine, to look at what the air quality impacts are of penetrations of DG, different types of DG, within the South Coast Air Basin.

This is a very good subject for a variety of different venues, not only in our work here in the IEPR but also is germane to work that the south coast is looking at for new rules for DG as well as the Air Resources Board's 2005 update to their '07 standard.

So, with that, I'd like to introduce Jack Brouwer, who is going to present the work that UCI has been engaged in over the last two years on this initial study.

MR. BROUWER: Thanks a lot, Mark. I realize it's the end of the day, and I'm going to have to go fairly quickly through my 80 slides. Actually, I have about 40, so it's not too far from the truth.

I will go fairly quickly through these, but hopefully you'll get a little sense of the research that we were able to accomplish, which was one of the first programs in the world to really assess air quality impacts of distributed generation.

A lot of studies had looked at emissions impacts, but didn't couple that then to a detailed air quality model to determine whether it had impacts on criteria pollutants. So we were very pleased that the Energy Commission funded this effort to look at air quality.

I'll present a project overview, some of the DG implementation scenarios, the CHP methodology, since that's what's relevant to today's workshop, and then present just a few results from our analyses.

The goals of our project were to construct a set of likely DG implementation scenarios, or DG scenarios, to evaluate those scenarios for determining whether air quality impacts were observed as a result of them.

Some were questioning whether an air quality model, a current state-of-the-art air quality model, would be sufficient in its resolution to detect DG at all.

So we did a very detailed sensitivity analysis of the model. I won't present any of the results of that today, but found that indeed it is sensitive enough.

We also coordinated our modeling activity with the California Air Resources Board and the South Coast Air Quality Management District, which ended up being a very fruitful collaboration amongst our modelers and the modelers from the two agencies.

Finally, we participated with the central California ozone study people to exchange some of our results, and its also leading to some follow-on effort that we're going to study DG impacts in the central valley as well.

So it was the environmental program of PIER that sponsored this effort. We focused on the South Coast Air Basin in the year 2010. We considered all types of distributed generation technologies and we had expertise in distributed generation as well as in air quality modeling that we engaged.

We also had several industry workshops that included utility participation and several of you who are in the audience actually participated in these workshops, to try to garner as much input as we could from the DG community as well as the utility community.

So let me talk a little bit about the implementation scenarios. It's a lot more than just assessing the emissions from these. It's trying to determine what fraction of energy needs might actually be met by DG, what types of technologies would actually be adopted, and then of course, even understanding the emissions that we'd expect from these DG in 2010. That's kind of a challenge in itself.

Besides, it makes a very big difference where you put these within the regional models.

So we need to know the spatial allocation. Also, depending upon the end use, it will have a different duty cycle. We have to address that, because the time dependence has an impact on air quality.

We have to understand whether there's any emissions that are displaced. CHP is one of the areas in which you could displace, for example, boiler emissions.

And then we had to make other estimates. And if you want to hear about those I'll talk to you about them later.

But one of the key resources we had was geographic information systems data for all five counties that were in the South Coast Air Basin. And from this we could determine whether there was an industrial sector, a commercial sector, or all sorts of other end uses represented at various spatial locations within the basin.

However, the resolution of that data was much more fine than our grid. As you can see in this direct comparison here, where all the grey dots indicate an activity sector. I've blown up this area here in Long Beach just to give you a little sense of the high level categories involved in this GIS data.

And you can see here, there are agricultural, commercial, education, industrial sectors. And we did some pretty sophisticated analyses just to extract this data from the GIS data base to the five kilometer by five kilometer resolution of our air quality model.

But we also based the types of DG that were adopted in each cell, the duty cycle in each cell, the emissions associated with that in each cell, on the basis of this GIS data.

And that led to several different distributions of DG power. We investigated those distributions on the basis of land use, which led to the distribution seen in the upper left hand corner.

And you can see it differs pretty substantially from population spatial distribution or, of course, an even distribution, which is pretty unrealistic or a population growth distribution which concentrates things more on the eastern portions of the basin.

We studied all of these for determining whether or not different scenarios that we don't believe are realistic but that could be an expected outcome of some policy would have any impact.

And this is just an example of some of the duty cycles that we incorporated. Various duty cycles for residential applications or commercial applications, industrial applications, etc.

Now, when we looked at all of the parameters that we had identified we came up with 39 factorial scenarios. That was just a few too many for us to analyze in any detail.

So what we did is we screened these scenarios and came up with five realistic scenarios, which use all of the market studies, all of the GIS information, everything that we could come up with to come up with as realistic an expectation of what we would get in 2010.

But some parameters we were unsure of. And in particular what was the DG penetration that we'd expect, how much would really be adopted by 2010. And we did a range between five and 20 percent of the increased power between 2002 and 2010.

We also did one variation which is related to the 2003, 2007 standards of the

California Air Resources Board, and what it addresses is how much early adoption of DG is there, how much is adopted essentially before 2007 when the stricter air quality standards come into play. So that's what this DG adoption rate addressed.

We also had 21 spanning scenarios. In reality we had about 43 spanning scenarios, but the official report only contains 21 because those are the ones we had sufficient detail for.

But they were essentially put in there to test items of scientific significance or to test for unexpected outcomes.

So what happens if we just put all these market studies together, and all the GIS information data that we have for the various activity sectors and the like, what do you really se with regard to sectors, and what types of technologies they adopt.

Well, for the most part you see almost all the DG going into the industrial sector. That was about 60 percent of the DG went into the industrial sector.

Other categories included institutional and commercial sectors, which took another 30 percent or so of the total DG that was installed. And you can see that we included DG up to 50 megawatts, so Richard, we included your gas turbines in that.

And you can see they actually made a significant contribution when you look at this kind of pink category here at the top of the industrial, and then the red one right below it. I think yours are below that even, right? All right.

And then, what types of technologies wee adopted? Well, it turns out that it's mostly gas turbines that were adopted here. About 50 percent of the power was produced by gas turbines, you had about five percent photovoltaics, and ten percent fuel cells.

Okay, what about the total emissions that these DG were contributing to the basin? For the most part, because these are clean technologies they contributed a very small fraction of the total power, or total emissions to the basin.

If you look here, even our dirtiest DG scenarios, the ones here on the left hand side of the chart, only contributed about a maximum of two percent to the total basin-wide emissions.

And if you look at realistic scenarios, these are the ones labeled R1 through R5, you see that it's less than .5 percent of the total basin-wide emissions, of major emissions that you see here.

I guess this is one of the main reasons why people thought hey, your model's not going to notice any difference.

Well, what did we do in regard to CHP? Well, in both of our industry stakeholder workshops DG manufacturers suggested that CHP should be considered for a large fraction of the DG that is adopted.

And we accounted for quite a bit and we looked at a variation, including 100 percent of the DG adopts a CHP strategy to a realistic strategy which ended up having about 30 percent of the DG adopting a CHP strategy.

But you can see, some entities suggested a much higher fraction, 40 to 60 percent or something like that.

So what we did, when we estimated, when we included CHP in our scenarios we estimated the total CHP adoption for each end use sector, and then we estimated a realistic heat recovery factor.

And that incorporates all sorts of things: inefficiencies associated with the CHP technologies, the mismatch between the thermal and the electrical production times, all of these things that you guys have actually been talking about today.

And then for that we got a total thermal heat recovered in each cell. But we had to assume that was going to replace some old boiler emissions and some new boiler emissions, and then evaluate the fuel offsets, etc. And then get the net flux of emissions in that cell that resulted from that.

We used data here that's recorded by Ianuchi (sp) et al. And we assumed an efficiency for old boilers and new boilers.

So, one of the key things here is to mention that we did a case where we assumed all DG adopted CHP strategy. Because we wanted to see what's the maximum potential impact that CHP could have in these realistic scenarios?

And what you see is that, for a lot of the criteria pollutant emissions and in particular for CO_2, there is a very significant difference and a huge reduction in emissions that CHP can provide.

No matter what technology you adopt, you adopt fuel cells, you adopt natural gas ICE's, diesel ICE's, microturbine generators, you see CO_2 emission reductions that go from 25 percent to 86 percent or so, and then reductions in CO of inorganic compounds and NOX, etc.

Now, this is assuming that you get 100 percent of adoption, so this is kind of a maximum achievable reduction that you can get from CHP, but it's very significant.

Now remember, in the subsequent slides we're going to apply this to the fraction of emissions that is only between two and .5 percent of the total emissions, so you won't see as significant a CHP impact in the scenarios.

So let's go to some of the simulation results. This is really a neat picture and I wanted to show it to you because of that reason, of the basin. It's a neat picture of the basin.

But it gives you a real good perspective on what we're dealing with when we simulate the South Coast Air Basin.

We have the ocean that sits to the west, primarily off ocean breezes that don't blow too hard, so they just push the emissions from the basin up against the mountains and essentially trap them there for a reasonable amount of time, allowing the atmospheric chemistry to take place, producing the nitrogen, producing the ozone levels and the particulate matter that we're concerned with.

So what do we do with that? Well, we put it into a model where we simulate the general dynamic equation for each species in each cell for each period of time.

And you can see here, we have a cell that's a fully three dimensional model and the dynamic equation counts for convection, diffusion, for sources and sinks like the emissions and the depositions, as well as the aerosol chemical kinetics and the homogeneous chemical kinetics.

So this is a very computationally intensive process, but it's the only process by which you can actually estimate then the air quality impact of these emissions.

So what happens when we look at a baseline case? And I'm going to show you a movie that shows the hour by hour concentrations of ozone throughout the basin.

And I'll show it to you a couple of times because what you see is that at midnight we have very low concentrations, they're on the order of 20 PBB or so throughout the basin.

But then you see, throughout the day and especially as you get into the early afternoon hours, quite a large concentration of ozone right up against the mountains there, just as we observe in reality.

And this sort of behavior is well predicted, we compared this model to measurements. And it well predicts what we measure in the eastern portion of the basin during an air quality episode.

Now we need to have this baseline emissions inventory and baseline case because we need something to compare it to. And so we also predict the baseline particulate matter concentrations.

I'm showing here only PM 2.5, that's the small particulate matter. The particulate matter that's often produced in this atmosphere as a secondary organic aerosol. So we're talking about the small particulate matter here.

And what you see are two major regions, but an especially high concentration of PM 2.5 in the eastern portion portions of the basin, in Riverside and San Bernardino counties. You also see some near Long Beach, which are associated with the port and with the refineries.

Now these happen to have different concentrations of sulphur and nitrogen compounds, and it's really an interesting thing in and of itself, but those are the areas where you have the key problems with particulate matter.

Okay, now you have this in your handout so I'm not going to actually go through this, because I'm already two minutes over.

Well, let me just show you what happens when we now add a realistic set of DG emissions, time resolved, spatially resolved activity sector resolved, duty cycle included and everything.

Well, we get this prediction. Do you notice any difference? Maybe? Here, let me show it again. It's pretty tough to tell the difference, I tell you. Too much information here.

Well, the key thing if you want to

actually tell a real difference, is to look at then a difference plot, right? Because it's very challenging to tell a difference if you look at that prediction there.

So this shows a difference between the realistic DG implementation scenario and the baseline case. Okay, so here we go. So now what we're seeing is that when you see green there is no difference. But when you see things that tend towards the red that's an increase in ozone, a local increase in ozone.

When you see things that tend towards the blue that's a local decrease in ozone. And what you see for this realistic case is really a very minor impact associated with DG but an impact nonetheless on ozone concentrations, with some locations showing a decrease and some locations showing an increased in ozone.

And that increased and decrease, if you look at it again here, is on the order of plus or minus two PPB. All right.

And then you can also look at PM 2.5. When I show PM 2.5 I don't show the movies because the standard is for a 24 hour average of PM 2.5. So I'm only showing then the basin-wide 24 hour average of PM 2.5.

And what you see is, in the areas of highest concentration, that's where we see the largest differences. But the differences tend to be both plus and minus again, on the order of one microgram per meter cubed.

And that's about the level of the sensitivity of the model, suggesting in this particular case, for a realistic case here, that we don't have a statistically significant difference. Now for ozone we can actually say there is that difference.

Other scenarios, however, that we tested showed a significant impact with regard to both ozone and PM 2.5.

So let me just summarize here. You see that the basin-wide total emissions are less than .5 percent. But we do see, especially at the peak time, you can see that in here, some impact on ozone concentration on the installation of DG.

And then you see the same PM 2.5.

So what happens if we look at different adoption rates of DG. Remember that we don't really know for the realistic cases how much people are going to adopt by 2010.

So if we increase that by four times, from the realistic case number one to a 20 percent of the new installed capacity, the new generated power in the South Coast Air Basin that is going to be met by DG, we see a more significant impact.

And that's what's shown here on R3 in comparison to R1. You can see that the magnitude of the impact is not changed, but the extent of that impact is changed. So what it essentially says is that you still see changes that are plus or minus two PPB, but they're more broad, they affect more of the basin.

Okay. Well, what happens if you apply CHP to these realistic cases? So what I'm showing here is two different things. What happens if you do low early adoptions so that most of the technology is adopted after 2007?

Then you get this ozone prediction on the left, which essentially shows a much lower impact of DG on the air quality in South Coast Air Basin.

So the, and we've done spanning scenarios where you look at everything being installed according to 2007 standards and according to 2003 standards, and it really actually is a very significant difference that we can attribute to DG installed.

If people would change that standard it will have an impact on air quality. We can show that with our results.

And then, the final thing is what happens if you introduce CHP into this realistic scenario, or remove CHP from the realistic scenario? Well, actually what it did was it ended up leading to decreases here then in ozone, that you can see here.

Primarily decreases in ozone, as opposed to the case where we had CHP. Hmm, that doesn't sound too good.

In this realistic case, what it ended up doing is, in the regions where we were VOC limited, meaning that we had plenty of NOX already there, an introduction of more NOX actually helped with regard to ozone concentrations. So that's actually a curious finding with regard to CHP.

However, if we go to a case where we are adopting more DG, that's DG that has a more significant impact, what we see is definitely a positive impact on air quality associated with CHP adoption. And that's what you see in comparison of the left hand plot to the right hand plot.

Again, magnitudes are about the same, plus or minus three in this set of cases. But you can see the extent of pollutant impacts is much reduced when you go to the CHP scenario. So the extent of air quality impacts is much reduced when you go to CHP.

Okay, I'm not going to show you any more movies. So, in summary, we found that the model we are using is sensitive enough to determine whether or not DG has an air quality impact.

We found discernible increases and decreases in ozone and PM 2.5 that we can directly attribute to that DG. And those magnitudes that we found on the realistic cases are plus or minus three PPB for ozone, plus or minus two micrograms per meter cubed of PM 2.5. And on the spanning scenarios we saw more impacts.

We also saw a very consistent result of maximum increases of pollutants in areas where we are already well out of compliance. Like the eastern portions of the basin almost always had an increase in pollutants, whereas the areas near the coast or in downtown LA often showed decreases. So that was consistent throughout all the cases.

And the final statement here then, on the major project findings, is that the DG air quality impacts in outer years that we simulate din some of these spanning scenarios could be significant, they could be significant depending on how it was done.

And then related to CHP, there are a few findings here. One in particular is that CHP emissions displacements in realistic scenarios do lead to a significant CO2 reduction, but a small reduction in the criteria pollutants.

Now that's when we essentially had only about 30 percent of the .5 percent of the total emissions going into the basin. So you can see how it doesn't have that significant an impact.

We found these mass increments of emissions that were relatively small. And that the DG capacity ended up being largely installed in industrial areas, not necessarily in residential or commercial sectors.

And then yo usee some information here then on the various technologies that were actually used by us in this simulation, 40 percent being gas turbines, which have great potential for CHP, internal combustion engines, microturbines, fuel cells, etc., which all have this sort of a CHP potential.

So I thank you for your time.

(applause)

MR. RAWSON: That was very quick.

MR. BROUWER: I wanted to be quick.

MR. RAWSON: Thank you. Were there any questions for Jack about the emissions work we've done within the PIER program? Richard?

MR. BRENT: Has South Coast seen this yet?

MR. BROUWER: Oh yes, the South Coast Air Quality Management District, we worked very close with them, and they know all about these results already. They saw a pre-release of the report, which was just posted on the website, just last week. Yes?

MR. TOTH: Steve Toth with BP. Question on the scenarios. To take from the earlier point around why we're trying to promote CHP from the standpoint of it deserves to be in the loading order because it can help in the net on an energy intensive basis benefit air quality.

Curious, could you do a scenario where you basically take out all the DG in your model and offset it with what would be the replacement energy. In other words, if you didn't have DG, what's going to be the replacement energy sources, and if that's the case what happens to that model?

Now, I know not all that energy's going to be local, we have imported power and other things, but I'd just be interested to see just on the benefit side whether DG alone also would contribute from a beneficial standpoint?

MR. BROUWER: Yes, that's a very interesting question. We did not do that scenario that you said. We actually did just the opposite scenario, where we said let's take away in-basin emissions and substitute it all with DG.

So it was just the opposite. And we actually found that that was very significant, it had a very significant impact associated with removing local power plants and replacing it all with clean DG essentially. And it was a positive impact in that regard.

MR. TOTH: Do you have that model up here?

MR. BROUWER: I don't have it here on this presentation, but we have done that scenario. So it's the opposite scenario of what you've just asked.

MR. TOTH: Great, thanks.

MR. BROUWER: Uh, now again, that case assumed 100 percent of the power coming from the basin, which is not necessarily realistic.

MR. TOTH: Right.

MR. BROUWER: Right, okay.

MR. EVANS: Peter Evans, New Power Technologies. The study that we're going to present tomorrow, one of the findings that to me was very surprising, we were looking at good beneficial DG projects in Silicon Valley, and specified projects typically under a megawatt, in fact mostly were under 500 kilowatts.

But one of the things that -- and we assumed for the purposes of our study that they were all '03 CARB certified equipment, that wasn't one of the focuses of the study.

But one of the things that came out of it was that all these projects, with the exception of a few, would still require local air issuance, because they're mostly over 50 horsepower, which I think is the cutoff in the air quality management district.

So anyway, my question is you used the

term significant to characterize some of the potential impacts of the penetration of DG or minute power in the basin. And i guess my question is, this is really a policy question.

In the scheme of things, is it still really worthwhile to do local air permitting processes on CARB-certified gear, especially when the '07 standards, but even the '03 standards.

Or is this something where we would say, well it's significant in the sense that you can measure it, but in terms of society and given the difficulty of going through that permitting process for a grocery store or a Costco, is that a good use of resources?

MR. BROUWER: Well, I can't answer the policy part of the question, but what I can say is that in the South Coast Air Basin we found that the AQMD does not require an air permit for CARB certified equipment.

MR. TOTH: So this might be a local thing.

MR. BROUWER: Right, okay. And I know that for a fact because we are testing CARB certified technologies at our own laboratories and we do not require, they do not require an air permit for those. As long as they're CARB certified. Now -- go ahead.

MR. EVANS: Well, the CARB certification program only applied to equipment that is exempt from permit, doesn't it? That's the way it works.

MR. BROUWER: Yes. Now, with regard to the question of significance, that's also a tough one to answer. I can only answer with regard to the statistical significance of the model. I can only tell you whether or not it's a real prediction of the model or just numerical uncertainty in the model.

I can't say whether or not it's significant with regard to whether AQMD would want to regulate that emission.

MR. EVANS: So when you use the term significant it's from an analytical standpoint?

MR. BROUWER: That's correct. So when I use it it's for the significance of the model prediction itself, not with regard to whether or not AQMD would be concerned about regulating that emission.

COMMISSIONER GEESMAN: You did raise a question about significant results in the out years. Which are the out years?

MR. BROUWER: We did not directly investigate any out year in this study, although we have proposed to do that in a follow-on study.

But what we did in one of our spanning scenarios is we projected a ten times increase in DG installation that may represent 2050, it may represent 2100, I have no idea what it would represent.

And when we did that there were some pretty significant impacts if the technology mix represented the 2003 standard and nothing more. So that's what we did, we took the 2003 standard, we said, then we put a whole bunch of it into the basin, and it did show a significant air quality impact.

Okay, one more question? Okay, thanks.

MR. TOMASHEVSKY: Okay, I guess we'll take just one general comment, and then we're going to wrap this up.

MR. O'CONNOR: Thank you. Todd O'Connor, I'm here wearing my hat for CADER. This year CADER is co-hosting it's annual symposium for distributed generation with CalSEIA, and the theme, which is why I bring it up now, is very relevant to what we've been discussing today and what we'll be discussing tomorrow.

And that is all power is local. And the conference will be held on September 7th through 9th at the Westin in Santa Clara, in the heart of Silicon Valley. And for the first time we are going to be hosting a golf tournament that CalSEIA asked to conduct so you can actually practice your all power is local golf swing, if you will.

And we're asking for the participants to the talks today, that have been tremendous, the policy implications are just beginning to unwind, the IEPR is hopefully going to be full bore by September, we'll look for the CEC to give its findings and recommendations.

We'll look for panels that have been the kind of panels that have been here before us today and will be here for us tomorrow. We're looking for participants, we're looking for sponsors.

There is a one letter description of the CADER Conference on the table, please take one on the way out, and I thank you for your time.

MR. RAWSON: Commissioners, did you have any closing comments?

COMMISSIONER GEESMAN: Just to thank you, Mark, and Scott for assembling such an informative day. Look forward to tomorrow.

MR. RAWSON: Great. Thank you. Public Comments May 6th. Next steps, after we will be using this input into the staff's drafting of the loading order white paper, which will then be a part of the Committee's policy paper later this summer.

So, we encourage you to submit comments and thanks for coming today.

(Thereupon, the workshop ended at 5:20 p.m.)

CERTIFICATE OF REPORTER

I, PETER PETTY, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Hearing; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing, nor in any way interested in outcome of said hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 9th day of May, 2004.